Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Exhibit 1

CPRE Program Independent Administrator's
Interim Report on Tranche 1 RFP

Exhibit 1

ACCION GROUP

COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY

INDEPENDENT ADMINISTRATOR'S REPORT

DUKE ENERGY CAROLINAS (DEC)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposal (RFP) – 600 MW

DUKE ENERGY PROGRESS (DEP)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposals (RFP) – 80 MW

CONCLUSION OF STEP 2 EVALUATION AND SELECTION OF PROPOSALS

April 9, 2019

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I. EXECUTIVE SUMMARY

On April 9, 2019, the Independent Administrator ("IA") for the Competitive Procurement of Renewable Energy Program ("CPRE") completed the evaluation of proposals for Tranche 1 for both Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"). On this date the IA delivered to the Duke Evaluation team the winning proposals. This ends the Tranche 1 RFP, with the expectation that each successful third party Market Participant ("MP") will promptly execute a Renewable Power Purchase Agreement ("PPA").

Summaries of the Tranche 1 process, and of the final selections are in the following sections. Because PPAs have not been finalized, the identity of projects and the successful MPs are not disclosed at this time. Project information and the identity of the successful MPs will be included in the final Tranche 1 report that will be presented after the contracting period is concluded.[1]

CPRE Tranche 1 was successful in establishing a competitive procurement process that will provide twenty years of renewable energy at pricing below Duke's Avoided Cost. In DEC, the average price per proposal is 36.93 $/MWh. In DEP, the average price per proposal is 31.24 $/MWh. The total nominal savings were estimated versus avoided cost over the full 20-year term. DEC is estimated to have $290.20 million in savings, and DEP to have $84.69 million in savings. Also, Tranche 1 succeeded in further clarifying the need to address ways to permit "shovel ready" renewable projects to move to development without delay. A number of MPs declined to provide the required proposal security [2] when informed that their projects were ranked in the competitive tier at the end of Step 1, suggesting to the IA that a number of projects holding positions on the transmission queue are not ready to be developed.

A total of 249 MPs registered to participate in the program for either DEP or DEC, and 28 submitted at least one proposal. For DEC, 58 proposals were received [3] for a total of 2682.72 MWs, and for DEP 19 proposals were received for a total of 1156.25 MWs. All of these proposals used solar photovoltaic (PV) technology; three included battery energy storage. After the IA completed the Step 1 evaluation, MPs for 20 of the proposals declined to provide the required proposal security, thereby effectively withdrawing from the CPRE Tranche 1. At the conclusion of Step 2, the IA determined that 12 proposals offered to DEC met the CPRE requirements and were recommended for PPAs. These proposals total 515 MWs. Two of those proposals included storage facilities. Notwithstanding a robust response from the market, the Tranche 1 procurement fell short of the goals of 600 MW by 14% (85 MW) for DEC. For DEP, the goal was to procure 80 MW. Three proposals qualified to be selected as winners, and the IA

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[1] All contracting is to be completed within sixty (60) days of this announcement.

[2] Proposal security was required to avoid the potential of completing evaluations with the selection projects that were unwilling to commit to execute a PPA. The proposal security was released for all proposals that were not selected as winners. The IA believes this requirement was a success in that only committed MPs had proposals move to the Step 2 review.

[3] As shown below, 58 proposals were initially submitted. The IA determined that one was erroneously submitted twice, and after confirming the MP's intent, one submission was set aside, resulting in 57 proposals being included in the Step 1 analysis.

recommends entering into PPAs with two projects for a total of 87 MW. IA's recommendation for DEP exceeds the Tranche 1 goal by approximately 9%.

The IA estimates that the cost of transmission system upgrades for all of the selected proposals will be approximately $5 million.

A significant number of proposals were withdrawn once identified as being on the competitive tier, thereby reducing the number of projects available for consideration in Step 2. The Step 2 evaluations identified system impact costs to be imputed to proposals resulting in some proposals being above Avoided Cost and therefore not eligible for selection.

Employing knowledge from our nation-wide practice, the IA estimates the investment in solar projects, excluding land costs, to be $1 million - $1.5 million /MW. Therefore, the IA estimates that the successful proposals, if they are completed, will result in capital investments of:

Estimated Capital Investment of Selected Projects

Solar Investment	DEC (515 MW)	DEP (87 MW)
$1 million/MW	$515 million	$ 87 million
$1.5 million/MW	$772.5 million	$130.5 million

The IA believes the Tranche 1 solicitation was fairly conducted, with all MPs having access to the same information at the same time, and the IA is unaware of any bias towards or against any Market Participant. Both Duke Energy Renewables, Inc ("DER") and the DEC/DEP Proposal Team submitted proposals, which were evaluated in the same manner as all other proposals.

II. SUMMARY OF SELECTED PROJECTS

Twelve proposals were selected as winners for DEC. As depicted here, the projects ranged from 7 MW to 80 MW for a total group of selected proposals totaling 515 MW. Two of those selected proposals included storage.

Three proposals were quantified as potential winners in DEP. The RFP established that up to 80 MW would be selected, with the possibility of exceeding that amount by up to 5%. The selection of all three finalist proposals would result in a total of 167 MW being selected, which was unacceptable. For this reason the IA recommends Duke accept two proposals in DEP for a total of 87 MW. The best ranked proposal was from a small project, which necessitated selecting the next best ranked proposal in order to get close to the Tranche 1 goal for DEP.

Figure 1
Summary of DEC Selected Proposals
(NOTE: MW sizes rounded)

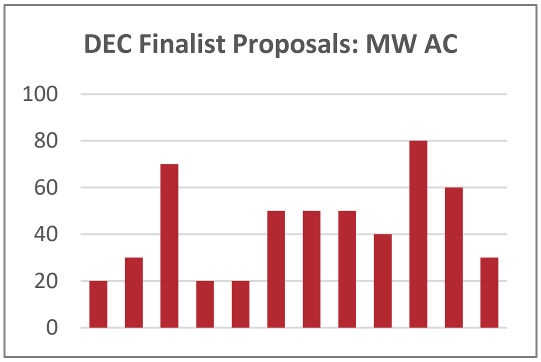
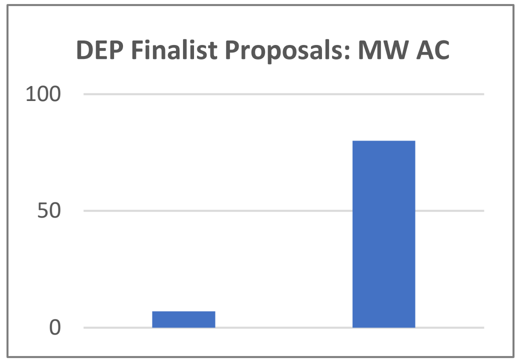


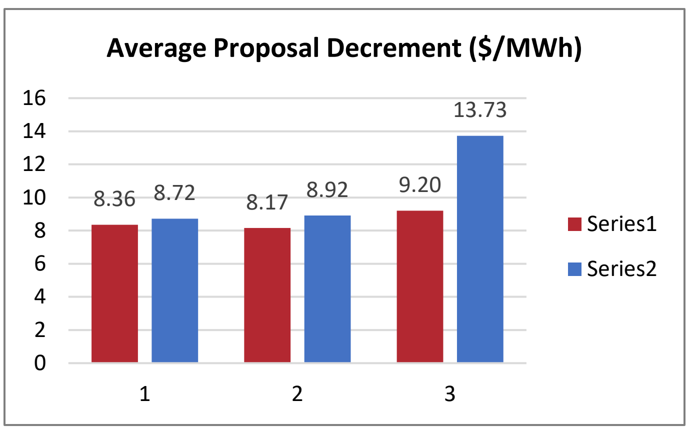
Figure 2
Summary of DEP Selected Proposals
(NOTE: MW sizes rounded)



III. SUMMARY OF EVALUATION PROGRESSION

The on-line proposal form required MPs to present pricing in the form of a price decrement to the respective DEC or DEP average Avoided Cost. The evaluation process determined which proposals would be below Avoided Cost, after assessing the cost of system upgrade costs, if any, to each project that would require transmission upgrades. [4] While the MPs priced their proposals by setting a decrement to Avoided Cost in each proposal, the decrement was not determinative of which proposals would provide the most value. Figure 3 presents the difference between the averaging of all submissions, and the average decrement after proposals withdrew or were eliminated.

Figure 3
Average Decrement – DEC & DEP



[4] MPs were required to include the cost of interconnection as part of their initial proposals. Transmission system upgrade costs for successful proposals are to be recovered through rates. The system upgrade costs of each proposal, if any, were imputed to the proposal to establish the full cost of each proposal.

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The reduction in the Average Decrement from the original submissions to Step 1 ranking reflects the removal of on proposal each in DEC and DEP.

Figures 4 and 5 depict the progression from submission of proposals to the final selection for both DEC and DEP. In DEC, there were 58 proposals, with 57 remaining after the IA conducted the non-price evaluation of project and proposal viability. Proposals were evaluated and ranked by system benefit, first at the conclusion of Step 1. The Step 2 evaluation of system upgrade costs, and the imputing of those costs to associated proposals, and proposals were then re-ranked. This process further reduced the number of proposals in DEC to 33.

The progression of proposals for DEP followed the same process, going from 20 submitted proposals to three proposals to satisfy the 80 MW requirement for Tranche 1. The most competitive proposals below Avoided Cost, after the Step 2 determination of system upgrade costs were selected as winners.

Figure 4
Evaluation Progression

	Submitted Proposals	Step 1 Ranking	Step 2 Ranking	Finalists
DEC	58	57	33	12
DEP	20	19	3	3

Figure 5
Evaluation Progression

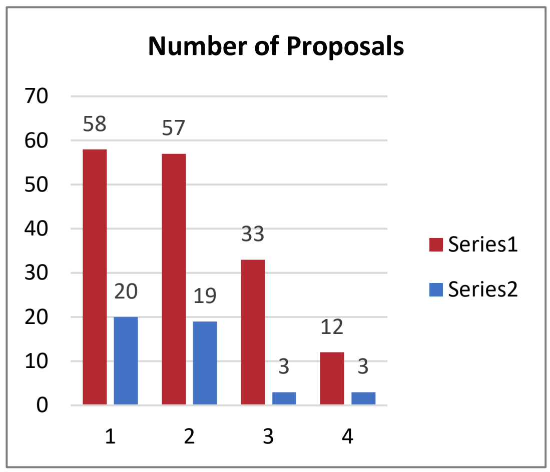
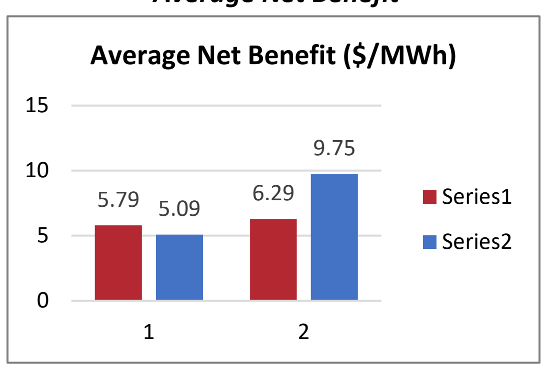


Figure 6
Average Net Benefit ($/MWh)

	Step 1 Ranking	Finalists (With T&D Costs)
DEC Average Net Benefit:	5.79	6.29
Total DEC Bids:	57	12
DEP Average Net Benefit:	5.09	9.75
Total DEP Bids:	19	3

The IA evaluation team determined the net benefit (See: Section VIII below) of each proposal to establish the ranking of proposals to be reviewed for system impact as part of the Step 2 process. Figures 6 and 7 summarize the Step 1 net benefit of proposals.

Figure 7
Average Net Benefit



The average net benefit for Finalists includes the system upgrade costs shown in Figure 7.

The evaluation process, including the withdrawal of proposals, reduced the capacity of the initial offerings to the finalist list. While the Step 1 ranking included a large field, the Step 2 process (and the withdrawal of proposals) significantly reduced the number of proposals ultimately available to be selected as winners.

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Tranche 1 included the opportunity for MPs to include storage in proposals. Proposals with storage were required to include production profiles for the project (8760 hours/year for the 20-year term), both with and without storage. The IA used these profiles to determine whether the MP reasonably projected the use of storage. The RFP required that the MP be responsible for dispatching the storage, and that it be recharged only from the associated renewable resource. Protocols in the PPA also included provisions that guide the MP in charging and discharging.

IV. SUMMARY OF LOCATIONS

The on-line proposal form required MPs to identify the location of their project and the proposed Point of Interconnection ("POI"). The IA confirmed project locations and corresponding Transmission Queue Application with the Duke Transmission Team. As expected, few projects located in transmission constrained locations were offered in Tranche 1. The geographic distribution of selected proposal sites is as follows:

Figure 8

GEOGRAPHIC DISTRIBUTION OF PROJECTS

	North Carolina	South Carolina
DEC	**9**	**3**
DEP	**1**	**1**

V. SUMMARY OF ELIMINATED BIDS - DEC

Throughout Tranche 1 proposals either withdrew or were eliminated during evaluation in Step 1 and Step 2. Figure 9 summarizes the reasons why proposals were eliminated.

Figure 9

DEC: Summary of Eliminated Bids Progression		
Reason for Disposition	**Proposals**	**MW AC**
MP Failed to Post Proposal Security	**20**	**865**
T&D System Upgrade Costs Resulted in Proposal Above Avoided Cost	**15**	**794**
Result of Step 1 Analysis – Proposal is Above Avoided Cost	**3**	**127**
MP Withdrew	**3**	**191**
Unique Disqualifying Reasons	**5**	**233**
Bids were more expensive to ratepayers than selected winners	**N/A**	**N/A**
Total:	**46**	**2,210**

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VI. SUMMARY OF ELIMINATED BIDS – DEP

Consistent with the description of the evaluation process in the RFP, at the conclusion of Step 1 all remaining proposals in DEP were ranked by benefit to the Duke system. After eliminating a duplicate proposal, the 19 remaining proposals were available for Step 2 evaluation of transmission and distribution system cost impact. The proposals were reviewed in ranked order with the Step 2 cost determination continuing until the program goal for DEP (80 MW) was reached without exceeding Avoided Cost. At that point the Step 2 evaluation of the remaining proposals was halted because additional system analysis could not improve the ranking of other proposals, especially if the review identified costs to be imputed to proposals.

Three proposals were identified as eligible to be selected. The IA recommends accepting the two best-ranked proposals, which will result in exceeding the goal by 9%, and not accepting the third for that would far exceed the Tranche 1 goal for DEP. Figure 10 represents the DEP proposal eliminations.

Figure 10

DEP: Summary of Eliminated Bids Progression		
Reason for Disposition	**Proposals**	**MW AC**
MP Failed to Post Proposal Security	**N/A**	**N/A**
T&D System Upgrade Costs Resulted in Proposal Above Avoided Cost	**3**	**148**
Result of Step 1 Analysis – Proposal is Above Avoided Cost	**N/A**	**N/A**
MP Withdrew	**N/A**	**N/A**
Unique Disqualifying Reasons	**1**	**75**
Bids were more expensive to ratepayers than selected winners	**13**	**842**
Total:	**17**	**1,065**

VII. SUMMARY OF PARTICIPATION BY DEC/DEP PROPOSAL TEAM and DER

Both DER and the DEC/DEP Proposal Team presented proposals in Tranche 1. These proposals were evaluated in the same manner as all other proposals. Proposals from each are included among the successful proposals.

The DEC/DEP Proposal Team proffered proposals that were selected from projects offered for acquisition. The IA conducted an audit of the acquisition process employed by DEC/DEP Proposal Team and will include findings in the final Tranche 1 report.

VIII. SUMMARY OF PRICE SCORING PROCESS

Each proposal was evaluated on four measures: the bidder's pricing information (using 3 price tiers), the facility MW AC capability, facility storage parameters where storage was included, and the MP's load shape information, as reflected in the 8760-production profile provided by the MP. The Evaluation Model utilized the bid input parameters to calculate each proposal's "Net Benefit" to the Duke Energy system on a twenty-year net present value of benefit per MWh. A proposal's net benefit can be described as the sum of facility's net energy benefit and the facility's capacity benefit, less the T&D costs borne by Duke Energy to accommodate the facility. That is:

Net Benefit = Net Energy Benefit + Net Capacity Benefit - T&D Cost

After the Step 1 initial ranking of proposals, the Transmission & Distribution system facility costs were calculated outside of the IA's Evaluation Model for each specific proposal for which the Proposal Security was provided, other than Late Stage projects [5]. The calculated Transmission & Distribution facility costs for a project were assigned to reflect the cost of adding the project to the Duke system. The evaluation model was then re-run to produce the final ranking of proposals at the end of the Step 2 evaluation.

The "Net Energy Benefit" was calculated as energy savings to Duke Energy resulting from the operation of the proposed facility. The energy savings for a facility can be described as difference between the Duke Energy marginal energy cost and the proposed facility's energy cost (as established in the submitted pricing). This analysis was run on an 8760 hour per year basis for twenty years.

The facility's Net Capacity Benefit is the cost savings to the Duke system from Duke deferring the addition of future generating capacity, if the facility were on-line. Similar to the calculation of Net Energy Benefit, this analysis was run on an 8760 hour per year basis for twenty years. The facility's resulting capacity benefit was estimated using the Duke system (DEC or DEP) avoided cost.

The Evaluation Model processed 20 years of data as submitted by the bidder; each of these years was processed individually. Since the bidder was required to submit pricing that conformed to 3 price tiers (Summer peak, Non-Summer peak, and off-peak), the evaluation model accounted for hourly details, such as weekend days, holidays, leap year impact, and Daylight Savings time shifts.

IX. SUMMARY OF IA DUE DILIGENCE

A. PROJECT SUFFICIENCY REVIEW

The IA Project Sufficiency Team ("PST") was responsible for performing a detailed technical evaluation of each project that was identified in proposals received in CPRE. The technical evaluation included a complete review of the project design and equipment specifications as well as a review of the experience of the MP's Project Team. This due diligence review was completed to confirm that any project the IA recommended for a PPA was technically capable of providing the service proposed.

In its initial examination, the PST reviewed each proposal and its associated uploaded documents to determine whether the response was "complete and conforming," that is, whether all of the required information met the RFP criteria. The PST found a number of deficiencies within or questions about the

[5] Late Stage projects included system upgrade costs in the proposal price and, therefore, were not included in the Step 2 system impact studies.

project design and initiated the "cure" process to provide MPs the opportunity to clarify the information provided with the initial proposals. Ultimately, all of the submitted proposals were corrected and deemed conforming. No proposals were rejected in the initial review due to a failure to establish the viability of a project.

After the Step 1 scoring was completed, the PST proceeded through its evaluation in the ranked order established by the price scoring. All proposals were reviewed for the sufficiency of the project, with projects receiving a full technical review as they were identified for inclusion on the competitive tier. This approach permitted the best-ranked projects to proceed to the Step 2 review without delay, and those drawn from the reserve list were reviewed sequentially.

Scores were assigned to each proposal using the Scoring Sheet identified in the RFP to establish a record of the individual reviews.

B. LEGAL SUFFICIENCY: SITE CONTROL, PERMITTING, SITE DESCRIPTION

The IA's legal team was responsible for assessing whether proposals had provided sufficient information to confirm the associated projects were capable of being constructed. In particular, based on prior experience the IA was committed to only recommending proposals to Duke that had secured site control of a tract that was fully described and where the developer had demonstrated knowledge of the permitting requirements to be met. A Site Control Acknowledgement Affidavit , the form of which was prepared by the IA, was to be submitted with each proposal, along with other documentation of site control. After bids were submitted, the legal team reviewed the following documents for completeness: Site Deed, Site Lease, Site Control Acknowledgement, Title Insurance Copy, Title Insurance, Title Insurance Report, Boundary Survey, Description of the Site, Easements, Environmental Studies, Facility Descriptions, Facility Permits, Other Permits, the Project Map, Project Map with Landmarks, and the Sitemap. After the curing process, all projects were included in the Step 1 price scoring evaluation.

C. FINANCIAL QUALIFICATIONS

The Financial Review conducted for Tranche 1 of the CPRE evaluated the credit-worthiness factors identified in the RFP (see Appendix F, item 6 – "Credit Worthiness"). The purpose of the financial review, as stated in the RFP, was to determine the "… financial assurances to meet schedule and milestones in PPA." The credit worthiness factor (Item 6) was assigned five percent of the bid score, equal to 50 points of the total maximum score of 1000 points.

Bidders who withdrew from Tranche 1 by declining to post Proposal Security or for other reasons were not evaluated.

D. TRANSMISSION AND DISTRIBUTION

Prior to the receipt of proposals for Tranche 1, the IA established transmission and distribution system review protocols with a sub-team of the Duke Transmission Team ("T&D Sub-team"). The T&D Sub-team was led by senior personnel. Duke Account Managers were not included in the Step 2 evaluation process. When proposals were received, the on-line proposal form required the inclusion of the transmission queue number assigned to the project. Before any system impact evaluation was conducted, the IA and the T&D Sub-team determined whether a proposed project had a valid interconnection queue number. One proposal was rejected as part of that review.

During the Step 1 evaluation period, the IA transmission team determined whether the proposed transmission path from the project to the Point of Interconnection ("POI") had sufficient site control for each parcel to be traversed, and whether the MP had included a reasonable estimate of interconnection costs. One proposal was unable to confirm sufficient transmission path site control, which was identified for Duke Transmission by the IA. [6] So-called Late Stage projects were identified as part of the proposal submission process, and those projects were excluded from the Step 2 system impact studies.

System impact was determined for proposals in ascending order of net benefit, as determined in Step 1. All projects that declined to post the proposal security were excluded from the Step 2 evaluation. It was apparent that the cost of adding some projects to the grid would make the all-in cost of those projects (that is, proposal cost plus the imputed system impact cost) far above Avoided Cost. The system impact of adding the successful proposals will be approximately $5 million. The system improvements required to accommodate the proposals that were evaluated but not selected would cost approximately $230 million.

X. CONCLUSION

Tranche 1 was successful in nearly reaching the targeted goal for DEC and meeting the goal for DEP. The unmet targeted capacity will be included in future tranches. Tranche 1 highlighted the challenges with transmission access when speculative projects in the transmission queue are treated as development-ready. As noted in the transmission review summary, $230 million in upgrades would be required to accommodate the uneconomic projects submitted in Tranche 1, after considering all projects with transmission queue positions preceding the CPRE Tranche 1.

[6] The proposal was determined to be otherwise sufficient and well ranked. The IA confirmed the MP would assume the risk of failing to secure a firm route to the POI, and execute a PPA if proffered, including the associated potential financial penalties.

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Exhibit 2

CPRE Program Independent Administrator's
Final Report on Tranche 1 RFP

Exhibit 2

DUKE ENERGY CAROLINAS, LLC
DUKE ENERGY PROGRESS, LLC

FINAL REPORT OF THE INDEPENDENT ADMINISTRATOR

RE:

DUKE ENERGY CAROLINAS (DEC)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposal (RFP) – 600 MW

DUKE ENERGY PROGRESS (DEP)
Competitive Procurement of Renewable Energy Program (CPRE)
Request for Proposals (RFP) – 80 MW

REQUEST FOR PROPOSALS FOR
THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY PROGRAM
TRANCHE 1

July 18, 2019

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FINAL REPORT OF THE INDEPENDENT ADMINISTRATOR
RE: DUKE ENERGY CAROLINAS, LLC; DUKE ENERGY PROGRESS, LLC
REQUEST FOR PROPOSALS FOR
THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY PROGRAM
TRANCHE 1

July 18, 2019

I. EXECUTIVE SUMMARY

Accion Group, LLC ("Accion") serves as the Independent Administrator ("IA") of the Competitive Procurement of Renewable Energy ("CPRE") program and began the assignment in January 2018. The IA participated in all aspects of the program, from preparing the draft and final Request for Proposal ("RFP") documents through the final evaluation of all submitted Proposals. This is the IA's final report concerning Tranche 1 of the CPRE program. This report provides an overview of Tranche 1 with detailed explanation of the processes and procedures that were employed. The IA also provides recommendations for improvements in Tranche 2.

Figure 1 presents a summary of the Tranche 1 Results.

Figure 1

	DEC	DEP
MW Procured	**465.50**	**85.72**
Average price/MWh	**$37.94**	**$38.30**
Nominal Savings over 20 years	**$228.00 Million**	**$33.17 Million**

Currently, the CPRE Program Plan approved by the Commission projects the need for three tranches of CPRE solicitations to be completed within the time frame contemplated by HB 589. Tranche 1 was the "beta" for the program and initiated the processes and procedures of CPRE to comply with the Rules established by the North Carolina Utilities Commission ("NCUC") and refine the program for future Tranches. As such, the IA believes Tranche 1 was a success.

The CPRE program is designed to procure 2,600 MW [1] of new renewable resources over a 45-month period provided those purchases are below Duke Energy's respective forecasted avoided cost calculated over a twenty-year term either through the Power Purchase Agreement ("PPA" or "RPPA") or from resources to be owned by Duke. Tranche 1 sought 600 MW of qualifying renewable resources for Duke Energy Carolinas ("DEC") and 80 MW for Duke Energy Progress ("DEP"); collectively DEP and DEC are referred to as the "Duke Companies" or "Company" in this report. The Duke Companies and its affiliates are permitted to participate in the CPRE program with projects to be constructed or acquired by

[1] As specified in the currently effective CPRE Program Plan, the revised procurement target is now 1,460 - 1,960 MW due to the increase of the Transition MW.

the Company to serve the goals of the CPRE program. Proposals from the Duke Companies were made by the DEP/DEC Proposal Team ("DEP/DEC Team"). [2]

The IA provided the web-based platform ("Website") for proposals submitted to DEC, DEP, and Asset Acquisition ("AA") proposals. The unregulated affiliate of the Duke Companies, Duke Energy Renewables ("DER"), participated in the same manner as other Market Participants ("MPs"). The IA Website maintained three separate and secure "Silos" for each of the three solicitations; all data related to these solicitations has been maintained by the IA on secure servers.

Proposals were received through October 9, 2018, when the Proposal submission period closed.[3] At that time, the ability for MPs to adjust their Proposal forms was terminated, including the ability to submit additional Proposals.

The IA received a robust number of Proposals and MWs in each Silo. Proposals included a balanced representation from North Carolina and South Carolina and ranged in size from seven to 80 MW AC of generating capacity in both DEC and DEP; 80 MW was the maximum size that could be submitted. The majority of Proposals would require transmission level service. There were also Proposals for projects that would interconnect to the Duke system at the distribution level. The Website functioned as desired in that it allowed a wide variance of Proposals to be submitted.

While MPs had the ability to provide renewable energy from certain technologies, [4] the IA received proposals for only solar photovoltaic ("PV") generation. Four of these projects proposed storage integration. The IA conducted the evaluation of Proposals as required for CPRE, that is with a preliminary evaluation of all Proposals in Step 1, followed by a Step 2 cost analysis study of the most competitive Proposals by the T&D Evaluation team, and a final step of the evaluation completed by the IA by imputing system impact costs to Proposals and conducting another iterative evaluation ranking of Proposals.

The Website remained the host of all CPRE activities through the Step 2 evaluation process and until each PPA was executed on July 8, 2019 and Performance Assurance security was provided. The IA retained all submissions by the MPs and all exchanges between the IA and MPs, as well as exchanges between individual MPs and members of the Duke Evaluation Team after the IA identified the Proposals selected for PPAs. Prior to the selection of finalists, the IA used the Message Board to communicate project-specific questions and comments with MPs, after consultation with the Duke Evaluation Team.

Before evaluating Proposals, the IA reviewed all Proposals submitted on the DEC and DEP Silos and completed a summary of each one. Each summary captured the core information provided with each Proposal and requested that the MP review and respond to the IA either confirming the accuracy of the information or identifying discrepancies. The Step 1 evaluation ranked Proposals into an initial

[2] Members of the DEP/DEC Team were subject to the Code of Conduct separation protocols, which isolated them from the Duke Evaluation Team.

[3] To avoid all inferences of bias, Proposals for projects to be originated by Duke and submitted by the DEP/DEC Team or DER were required to be submitted no later than October 8, 2018. Proposals by the DEP/DEC Team for projects selected for acquisition as part of CPRE were submitted on November 16, 2018.

[4] Tranche 1 accepted renewable energy resources as identified in G.S. 62-133.8(a)(8), with the exception of wind, swine, and poultry waste powered facilities.

Competitive Tier ("Competitive Tier"), Competitive Tier Reserve ("Competitive Tier Reserve" or "Reserve List"), and released Proposals.

On April 9, 2019, the IA completed the selection process, and final status notifications were sent to MPs for each Proposal. At that time, the IA created a separate message board for exchanges between the MPs of the Finalist Proposals ("Finalist MPs") and the appropriate Duke Personnel. Also, at that time, the same Duke Personnel were given access to the Proposal Books of the Finalist Proposals for review.

Subsequent to the notification of the parties representing winning proposals, two selected winning proposals chose to not proceed, one each in DEC and DEP. In DEC, there were no other active proposals remaining after Step 2, so the final results for Tranche 1 in DEC reflect the impact of this project withdrawing prior to signing the PPA. In DEP, the IA reached out to the MP with the next most competitive Proposal and substantially replaced the MWs of the withdrawn Proposal by the July 8, 2019 deadline. [5]

Attachment 1 sets forth the identity of the winning Proposals and those MPs that sponsored a winning Proposal but elected to withdraw.

The IA believes the CPRE Tranche 1 solicitation was conducted fairly and all MPs were given equal access to all information at the same time. The evaluation of Proposals was completed without bias towards or against any qualifying technology or participant. Further, the separation protocols that isolated Proposals from Duke Company personnel, including the Duke Evaluation Team, was strictly enforced. While the T&D Evaluation team had, out of necessity, the identity of projects as part of the Step 2 review, the IA is unaware of any instance where Duke personnel had access to project-identifying information from Proposals prior to the completion the CPRE Step 2 and the release of data to the Duke Evaluation Team. [6]

II. LESSONS LEARNED FROM TRANCHE 1

As the "beta test" of the CPRE Program, the IA is pleased with the accomplishments and success of Tranche 1. Below are observations and suggestions of the IA drawn from the Tranche 1 experience. The IA offers these suggestions as ways to improve the program for Tranche 2.

A. TRANSMISSION AND DISTRIBUTION EVALUATION PROCESS

The basis for these recommendations is discussed in the body of this report and summarized here:

1. There is a need for the Tranche 2 T&D system upgrade "base case" to better represent projects that will receive transmission and distribution services. The IA will work with the T&D Evaluation team to propose threshold standards for projects to be included in the base case. The Proposal will include a focus on upgrade cost and duration of necessary construction.

[5] The withdrawal in DEP occurred less than two weeks before the deadline for completing PPAs.
[6] There were three instances when MPs contacted members of the Duke Evaluation Team. Each time the Duke personnel declined to discuss the CPRE program and notified the IA.

2. Better locational guidance should reflect the commitment of transmission capacity to serve the successful CPRE Tranche 1 projects.
3. The Tranche 2 T&D system upgrade "base case" analysis should:
   - Exclude each project proposed and eliminated in Tranche 1 after it was established that upgrade costs would result in the project being well above avoided cost.
   - Only include the largest interconnection request when a project has multiple queue positions of differing sizes.
4. The IA should be included in all discussions with MPs until PPAs are signed in order to confirm the discussions are consistent with representations in Proposals concerning interconnection.
5. Duke Interconnection Account Managers should be included more on the T&D Evaluation team and actively engage in the Proposal analysis process, subject to following the appropriate communication protocols.
6. The IA should maintain a central ledger showing Proposal activity and current evaluation status. This is to be shared among all T&D Evaluation personnel and would be updated on a regular schedule.
7. Incorporate into the standard Proposal analysis document a more explicit discussion of risk and construction requirements needed to meet commercial operating dates.
8. Include reactive analysis as a standard part of the T&D system upgrade cost analysis process.

B. DOCUMENTS

Project documents were required as part of the due diligence review of project viability and state of completion. The goal of permitting so-called "shovel ready" projects to move forward could only be met by MPs confirming their projects were more than conceptual. A surprising number of Proposals were submitted with incomplete documents, including such basic items as proof of site control. During Tranche 2, the IA intends to continue to use the cure period to provide MPs the opportunity to meet their burden of proof with appropriate project documentation, rather than rejecting Proposals without the opportunity to correct misunderstandings and complete forms. While the cure period will continue to be limited to the Step 1 period, the response requirement for cures will be restricted.

The IA required identification of the transmission path from the project to the proposed Point of Interconnection ("POI"). A number of MPs failed to provide this information with their Proposals and were permitted to rectify the omissions during the cure period. The IA will use the pre-proposal period to impress upon MPs the need to identify each tract of land that would be crossed to reach the POI along with proof of site control of the path for the term of the PPA.

The Tranche 2 proposal form will include an acknowledgement that the MP is responsible for the accuracy of all documents. The IA is hopeful this will encourage MPs to be more attentive when submitting Proposals, so the IA need not require replacement documents, thus permitting the economic evaluation to occur more promptly.

Some MPs were unaware of which permits would be required for their project. The Tranche 2 Proposal form should include a form identifying the permits that could be required, and a "check off" identifying those applicable to the project.

Proof of Title Insurance was required as a tool to confirm site control. Few MPs provided the documentation. The IA is exploring additional ways to confirm sufficient site control of project sites and the transmission path.

Based on the experience in Tranche 1, the IA recommends the following requirements for documents to provide details on the generating facility design:

1. The Tranche 2 RFP and Proposal Form should include a requirement for MPs to provide the PV Syst input/output parameters and related calculations/work papers supporting the proposal's 8760 energy production profile. Had this been required in Tranche 1, some or all of the miscommunications between the IA team and certain MPs would have been avoided.
2. A required document entitled "Generating Facility Description" should describe or include: a) major structures related to the production of electricity; b) key equipment components (e.g., solar PV modules, inverters, transformers, energy storage devices if applicable); c) model numbers, nameplate capacities, spec sheets etc., as applicable; and d) transmission lines and electrical equipment leading to the POI with the existing electric grid. This facility description should be of sufficient accuracy and completeness that it can be inserted as an exhibit into a PPA to represent the exact facility that will be constructed and operated to meet the PPA terms and conditions.

C. PROPOSAL SECURITY

The need for Proposal security was confirmed in Tranche 1. At the same time, the process can be improved by the IA giving MPs more advanced notice of when Proposal security will be due, rather than the seven-day notice provided in Tranche 1. This was especially challenging for MPs during the iterative process of Step 2 with projects on the Competitive Tier Reserve who were subsequently moved to the Primary Competitive Tier after the initial completion of Step 1.

The IA proposes to provide a "two-step" approach whereby the IA will provide the MP with a preliminary notice that a project is under review and that a notice that Proposal security is required will be forwarded within one week.

D. UTILITY SELF-DEVELOPED PROPOSALS

As outlined in the IA's role in Section III, an important part of the IA's role is to ensure equitable treatment of all Proposals, including both third party Proposals and utility self-developed Proposals. Specifically, the NCUC established items (iv), (viii), and (ix) as the IA's responsibilities:

> (iv) Develop and publish the CPRE Program Methodology that shall ensure equitable review between an electric public utility's Self-developed Proposal(s) as addressed in subsection (f)(2)(iv) and proposals offered by third-party market participants.

(viii) Evaluate the electric public utility's Self-developed Proposals.

(ix) Provide an independent certification to the Commission in the CPRE Compliance Report that all electric public utility and third-party proposals were evaluated under the published CPRE Program methodology and that all proposals were treated equitably through the CPRE RFP Solicitation(s).

Based on the experience in Tranche 1, the IA recommends revising the Proposal security requirements for the DEP/DEC Team. Proposal security or some functional equivalent should be required in the case of both Duke self-developed projects and Asset Acquisition projects that the DEP/DEC team elects to sponsor. The IA will work with Duke to develop an appropriate structure for use in Tranche 2, which will be provided to the NCUC for consideration.

In Tranche 1, two winning Proposals withdrew after being selected as finalists after the close of Step 2. One Proposal was from a third-party MP and the other was from an Asset Acquisition Proposal sponsored by the DEP/DEC Team. The impact of the third-party MP withdrawing late in the process was mitigated by the existence of the non-refundable Proposal security. [7] The utility's Asset Acquisition winning Proposal that withdrew did not have Proposal security [8] and the related project developer was not obligated to provide comparable security in the event of withdrawal. In effect, the DEP/DEC Team and the developer had a free option to withdraw at any time, which the IA believes was an unanticipated result. [9] This issue arose during the final stages of the post-selection period, so fully developed recommendations for preventing this from reoccurring are being developed by the IA and Duke personnel and will be provided during the Tranche 2 formative stage. The recommendations will address ways to have both all Duke Proposals and developers of Asset Acquisition projects held to the same performance standards as MPs offering PPA Proposals. This issue is discussed in more detail later this report.

E. ASSET ACQUISITION

The IA is working with Duke to develop and clarify expectations for processing of Asset Acquisition proposals received from Market Participants to ensure a fair and transparent process and facilitate concurrent and post- review by the IA. This includes the communications through the website and other means with MPs, processing of proposals within Duke, and the process utilized by Duke to rank and select proposals for possible submission as Asset Acquisitions.

The Tranche 2 RFP should provide clear expectations/requirements for agreement between Duke and a Market Participant to in order for Duke to submit an Asset Acquisition proposal. For instance, a Letter of Intent covering principal terms and conditions should be required.

F. TRANSMISSION QUEUE ISSUES

After Proposals were received in Tranche 1, the IA and Duke T&D personnel worked to confirm the eligibility of each project. It soon became clear that the queue numbering system created an

[7] As of the date of this report, the Proposal security payment had not been received.
[8] The RFP expressly waived the Proposal security requirement for utility self-developed Proposals.
[9] The reasoning behind the RFP waiver of Proposal security from the DEP/DEC team related to the fact that DEP/DEC would be unable to obtain a letter of credit in which DEP/DEC was both the beneficiary and applicant/obligor.

unnecessary challenge due to numerous different queue numbering methods. To illustrate this problem, the following are a list of possible queue numbers attached to a project: the queue number assigned by Duke Transmission, the queue number for projects registered with the Federal Energy Regulatory Commission ("FERC"), the queue numbering for North Carolina, the queue numbering used in South Carolina, and, in some instances, unique queue numbers assigned by Duke Account Managers.

To avoid future confusion, the IA will work with Duke to develop a unified project documentation system for Tranche 2 that will allow the IA to more efficiently assess and evaluate Proposals. This review will include developing a form to compare and confirm the projects associated with queue numbers as presented by MPs and assign one reference number to be used in the Step 2 process. For Tranche 2, the IA and the T&D team will reconcile in a sequential way all queue numbering, based on date of the MP requesting interconnection.

G. PROCESS RECOMMENDATIONS

The IA makes the following recommendations for Tranche 2, based on the Tranche 1 experience:

1. RFP Document

The IA recommends the following three general changes to the RFP:

a. Add definitions of the Step 1 ranking classifications; "Primary Competitive Tier," "Competitive Tier Reserve," and "Release List" in Section F on Proposal security (possibly in Section F on Proposal security).

b. Change the definition of the Proposal security calculation to match the term "Generating Capacity MW AC" supplied in the Proposal Forms.

c. Change some of the "non-economic criteria" in Appendix F to pass / fail when appropriate, such as Credit Worthiness to remove risk to Duke through the posting of Proposal security.

2. Proposal Form

The IA has the following recommendations to the Proposal Form:

a. Agree within Duke on a standard term to represent the output capacity for the term "Generating Capacity" to avoid confusion. Having all the terms such as Generating Capacity MW AC, Total DC Capacity [MW], Contract Capacity [MW], Installed Inverter Capacity [MW], and Max Design Capacity MW AC may be unnecessary.

b. If the term "Insta DC Rating [kWpDC]" is needed in future Proposal Forms, change the unit from kW to MW.

c. Remove "Decrement" from the calculated prices since the price that the bidder will be paid is not a decrement to the bidder.

d. Explicitly list the Proposal security calculation on the Proposal Form.

e. Investigate why multiple bidders had trouble selecting the correct drop-down box for Technology.

f. Investigate using a standard format for all queue numbers.

3. Evaluation Process

The IA offers the following recommendations to the Evaluation Process:

a. Update guidance for MPs regarding area of transmission congestion.

b. Duke T&D Account Managers should be included in T&D Evaluation team and included in the Proposal analysis process, and thereby will have access to the ranking knowledge earlier in the review process.

c. The IA should maintain a central ledger showing Step 2 activity and status of each proposal review. This would be shared among all T&D Evaluation team members and would be updated on a regular basis.

d. Create a better way of understanding construction timing; a standard approach to documenting the likely time constraints would be helpful. A table such as Figure 2 should be inserted in each standard cost analysis document.

Figure 2

COD Risk Due to Transmission?	Earliest Feasible COD
Moderate	To meet a COD of 1/7/2021, this Proposal would need to provide notice to proceed by 01/1/2020. A typical interconnection study process is approximately 1 year. Only after the study process can notice to proceed be issued. Additionally, this Proposal requires coordination with SCEG which could impact the feasibility of COD.

III. INDEPENDENT ADMINISTRATOR

A. ABOUT THE IA

With an average of more than thirty-five years of in-depth experience in electric, gas, water, and renewable utilities, Accion Group's diverse consortium of consultants provides insightful, candid, and practical advice to the utility industry and their associated government regulatory bodies. Headquartered in Concord, New Hampshire and consulting affiliates nationwide, Accion's specialties range from competitive procurement and utility management to construction monitoring and nuclear decommissioning.

Since its incorporation in 2001, Accion has been routinely involved in high-profile consulting engagements, thus securing a reputation as one of the premier firms providing independent review of utility procurement practices. Accion has served as Independent Administrator, Independent Evaluator, Independent Monitor, or Independent Observer to state commissions on competitive solicitations in major markets including California, Hawaii, Georgia, Colorado, Montana, Oregon, Florida, the Carolinas, and Arizona. Accion Group has also assisted utilities in the preparation for, and the conduct of, power supply solicitations in Maryland, Massachusetts, and Nevada. Having reviewed Proposals for generation by renewable sources (including wind, solar, bio-mass, wave action, storage, low-head hydroelectric, geothermal, and methane capture), distributed generation with storage, and the construction of as well as facilities using nuclear power, natural gas, and coal fuels, our consultants are well-versed in the subtleties of utility procurement practices. Accion Group's ultimate goal as IA is the same as the purchasing utility and state regulators: ensuring the solicitation obtains the best deal possible for ratepayers, given current market and regulatory conditions in terms of both price and non-price factors.

B. THE IA'S ROLE IN THE RFP

As IA, Accion conducted Tranche 1 on a website custom made for the purpose. The IA designed and implemented the evaluation of CPRE Tranche 1 Proposals in order to determine those Proposals which offered the greatest value to the ratepayers and recommend those Proposals for contracting with the Companies. The North Carolina Utilities Commission ("NCUC" or "Commission") required the IA perform the following tasks: [10]

(i) Monitor compliance with CPRE Program requirements.

(ii) Review and comment on draft CPRE Program filings, plans, and other documents.

(iii) Facilitate and monitor permissible communications between the electric public utilities' Evaluation Team and other participants in the CPRE RFP solicitations.

(iv) Develop and publish the CPRE Program Methodology that shall ensure equitable review between an electric public utility's DEP/DEC Proposal(s) as addressed in subsection (f)(2)(iv) and proposals offered by third-party market participants.

(v) Receive and transmit proposals.

(vi) Independently evaluate the proposals.

(vii) Monitor post-proposal negotiations between the electric public utilities' Evaluation Team(s) and participants who submitted winning proposals.

(viii) Evaluate the electric public utility's DEP/DEC Proposals.

(ix) Provide an independent certification to the Commission in the CPRE Compliance Report that all electric public utility and third-party proposals were evaluated under the published CPRE Program methodology and that all proposals were treated equitably through the CPRE RFP Solicitation(s).

This report addresses how Accion completed each task and the results of CPRE Tranche 1.

IV. WEBSITE

Accion Group provided the RFP Website ("Website") for CPRE Tranche 1 to operate as a secure platform for the solicitation process including bidding, evaluation, and contracting. Below is an overview of each major feature that was enabled for users within the Duke Tranche 1 CPRE program.

[10] NCUC Docket No. E-100, Sub 150; Rule R8-71(d)(5)

A. SCHEDULE

The "Schedule" page displayed the solicitation schedule. Registered users received an email if new events in the schedule were posted or if the schedule was updated.

B. ANNOUNCEMENTS

The "Announcements" page displayed public announcements regarding the solicitation. When posted, registered users received the announcements via email.

C. REGISTRATION

The IA utilized a login registration on the website for purposes of privacy and security. Interested parties were required to register on the website prior to filling out a Proposal form or gaining access to pages such as documents and Q&A.

D. USER PROFILE

Allowed users to update their contact information, and turn on or off email notifications when new documents, announcements, or scheduled events occurred.

E. TUTORIAL

The IA crafted tutorials in both written and video formats to guide individuals in the use of the website. When an individual registered on the website, an email was sent to them with the written tutorial attached. Both tutorials were posted on the “Tutorials” page on the website and could be accessed prior to registration.

F. DOCUMENTS

The “Documents” page displayed all public documents related to Tranche 1. When new documents were posted, registered users received a notification via email. The Documents page was made available after registration.

G. Q&A

The “Q&A” page was a forum for registered users to ask non-project specific questions. All questions were anonymous and could be viewed by all registered users. Each question was posted once the IA submitted a response. Users who asked questions received a notification via email when the IA responded to their question. Following the close of the Proposal submission period, the Q&A page was disabled for further questions, though the prior questions and answers remained viewable.

H. MESSAGES

Prior to the Proposal submission date, the “Message” page was used only for questions or comments which disclosed confidential project-specific information, and therefore could not be asked via the Q&A forum. This feature was available after registering as a Market Participant (“MP”). After the Proposal period closed, all communications with MPs who submitted Proposals was conducted via a “Finalist Messages” page. This page was used by Duke Evaluation Team members, the IA, and MPs. As with the pre-bid Message Board, these exchanges were preserved for future review.

I. PROPOSAL MANAGEMENT

The “Proposal Management” page acted as the homepage for all activities relating to an individual MP’s Proposals. From this page, MPs could complete Proposals and redirect to a Proposal’s bid form, designate contacts associated with each Proposal (who received emails when Proposal related activity occurred), upload required bid form documents, create, clone, or delete a Proposal, and redirect to the “Proposal Books” page, which contained all files and documented history relating to individual Proposals.

V. OVERVIEW OF TRANCHE 1 CPRE PROPOSAL PROCESS

The CPRE Tranche 1 solicitation was broken into three divisions: Duke Energy Carolinas, Duke Energy Progress, and Asset Acquisition. This division was reflected on the Website where each solicitation had its own site, or “Silo,” within the Website. The separate Silos were used so that all data associated with the particular solicitation was self-contained, instead of being co-mingled with unrelated data. The data on each Silo was preserved for future review. The three Silos had identical structures and varied insofar as to accommodate minor differences in the solicitations. The Duke Energy RFP solicitation Website was released on April 6, 2018.

To register on a Silo, interested users were asked to read and agree to the terms and conditions put forth by the Independent Administrator, complete a “reCAPTCHA check,” that is “I am not a robot,” for website security, and complete the standard registration information, including a primary and secondary contact. Further, each individual had the option of registering as a Market Participant, or Non-Market Participant (“Non-MP”). Once registered, each individual received an automatic email notification acknowledging successful registration to the Silo along with a temporary username and password, which could be changed after login.

General information regarding the solicitation was made public upon the release of the Website. Certain features were made available to non-registrants, including the solicitation schedule, any announcements made thus far, public documents, viewership to Q&A, and website tutorials in both written and video formats. All other public information was available to registered users on the Silos; this included the Q&A forum, the Messages forum, and, following release of the Proposal form, the Proposal Management page. The Duke Companies Proposal Team required expanded Website access, and the IA selectively changed their registrant title to “DE Admin,” which gave access to additional features on their respective Silo.

The Website was designed to be the medium for all CPRE related activities. As stated previously, embedded in the Website were three Silos, each representing a unique CPRE Tranche I process. Each Silo automatically saved all user activity tagged with the user information and a time and date stamp. Additionally, the IA strictly encouraged all participants to use the Website for all CPRE activities, thereby ensuring a complete record of the solicitation process.

Beginning on May 11, 2018, draft RPPA and RFP documents were available to registered users for the purpose of the commenting period. All registered users had access to these documents. Registered users were invited to provide comments on a special “Comments” page. Interested persons, and

Figure 3: Standard Proposal Book File System

especially MPs, were invited to review the draft documents and offer suggestions that would enable them to offer robust Proposals. In effect, interested parties were invited to help draft the RFP documents. The Comments page separated each RFP document into individual sections with the opportunity to provide explicit changes by "red-line" revisions, accompanied by a brief explanation of the intended result. While the approach has been very successful in other jurisdiction, the response in Tranche 1 provided few red-lined changes and the comments were along the line of "this section should be changed", without specific textural suggestions. The IA is hopeful there will be a more engaged response in Tranche 2.

On July 10, 2018, the Proposal form was released on the Website to all MPs. An announcement was made on each Silo, and an automatic email notification was sent informing the MPs of the release. When an MP created a Proposal, a corresponding Proposal Book folder was automatically generated within the MP's Proposal Books. A standard Proposal Book folder is shown in Figure 3, depicting subfolders containing uploads from the Proposal Form (Proposal Support Docs; Other Eligibility Documentation), Proposal submission and messaging history (Proposal History), and documents uploaded post submission period (Cure Documents).

The MPs were given nearly three months to complete the Proposal form on their respective Silo. During that time, the IA monitored the Website daily to ensure the functionality of the Website and to monitor and respond to all general and project specific questions. The IA achieved this by updating the schedule when appropriate, posting announcements, updating the FAQ's page, and responding to posts on the Q&A page and the Message Board in a timely manner.

VI. PRE-PROPOSAL SUBMISSION ACTIVITIES

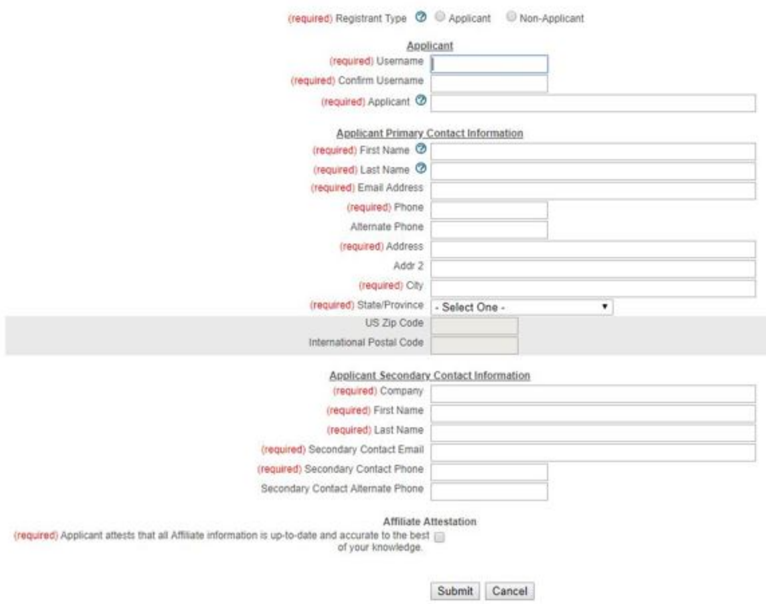
A. REGISTRATION

On April 6, 2018, Accion Group, opened registration on the Website. The Website contained three Silos: Duke Energy Carolinas, Duke Energy Progress, and Asset Acquisition. Once the Website was made public, interested parties had the ability to register on any Silo as Non-Market Participants or Market Participants. Registration on the Website remained open throughout the Tranche 1 CPRE process.

Registration was made straightforward and secure. The Registration page was accessed via the homepage of the Website through a tab on the menu bar titled "Register." Upon clicking the tab, users were introduced to the Terms and Conditions put forth by the IA, which they were then required to read and agree with to proceed. Users were then directed to a security page where the Website utilized *reCAPTCHA* technology to authenticate registrants.

Users were then transferred to the Registration Page, pictured in Figure 4. Registration was a crucial first step in the online solicitation for documentation purposes. Once registered, all user activity on the Website was automatically saved with an individual's identifying data. This provided a complete history of all CPRE related activities which could be tied to individual users.

Figure 4: Registration Page on the Website



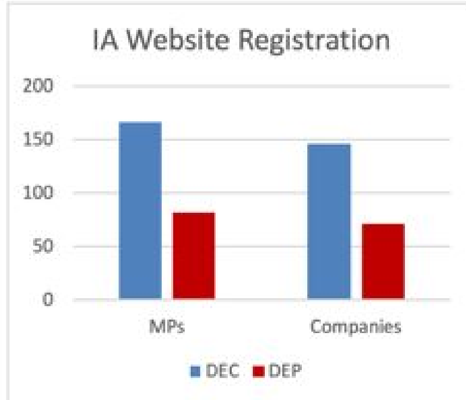
As highlighted on the top of the Registration Page, users were required to Register as either an Applicant or Non-Applicant, which is synonymous with Market Participant and Non-Market Participant. Non-MPs had restricted use on the Website compared to MPs. This allowed Non-MPs to have necessary access to understand the progression and process of the CPRE program without participating as a Market Participant. Likewise, MPs had all necessary tools to fully participate in Tranche 1 on the Website. Figure 5 identifies Website access granted to Non-MPs and MPs.

Figure 5: Access to the Website for Non-MP's and MPs. Check marks signify access.

	Non-MPs	MPs
Schedule	✓	✓
Announcements	✓	✓
Documents	✓	✓
Viewership to Q&A	✓	✓
Q&A		✓
User Profile	✓	✓
Tutorial	✓	✓
FAQ	✓	✓
Proposal Management		✓

Registration was available throughout the Tranche 1 process; however, Figure 6 represents the number of users registered to the Website as of the Proposal Submission deadline on October 9, 2018. Within the DEC Silo, 167 MPs registered from 147 different companies. Within the DEP Silo, 82 MPs registered from 72 different companies. A list of states and territories represented on the Website is shown in Figure 7.

Figure 6



The IA is satisfied with the dissemination of information about this RFP. Throughout the submission process, the Website received 364 MP and Non-MP registrants from thirty-four (34) jurisdictions, including the District of Columbia, and two Canadian provinces. These figures confirm that there was significant engagement from a wide range of companies.

Figure 7: Registration statistics on the Website from April 6, 2018 to October 9, 2018

State / Territory	Registered Users
Alabama	5
Arizona	5
California	44
Colorado	6
Connecticut	2
District of Columbia	6
Florida	30
Georgia	21
Hawaii	1
Idaho	2
Illinois	13
Indiana	3
Maryland	6
Massachusetts	1
Minnesota	3
Mississippi	1
Missouri	2
Nevada	1
New Hampshire	3
New Jersey	5
New Mexico	1
New York	10
North Carolina	128
Ohio	2
Ontario CA	5
Oregon	1
Pennsylvania	3
Quebec CA	1
South Carolina	18
Tennessee	4
Texas	19
Vermont	1
Virginia	7
Washington	4
Total:	364

B. IA GUIDANCE AND COMMUNICATION

1. Tutorial and Documents Pages

The IA maintained daily oversight of the Website and provided all means of Website and CPRE guidance. Within the Tutorial page, registrants could access a seven-page written tutorial overviewing the Website navigation, its features, and how to properly complete a Proposal form, as well as a six-minute video walkthrough highlighting the same. The IA also utilized the Documents page to post helpful information regarding the CPRE process, including the RFP and RPPA, Grid Locational Guidance, and Late Stage information. Before the Proposal submission deadline on October 9, 2018, the IA uploaded more than 60 documents.

2. Q&A and Messages

For any questions or concerns, MPs contacted the IA via the Q&A or Messages pages. The IA created these pages to ensure that reasonable and efficient communications could be completed and documented on the Website. If the IA received phone calls or emails from MPs, the inquirer was immediately directed to continue the correspondence via the Website.

The Q&A page and the Message Board were created for distinct purposes. The Q&A page was open from the release of the Website on April 6, 2018, and closed at the end of the Submission period, on October 9, 2018. Questions on the Q&A page were non-project specific, and could therefore be useful to many Tranche 1 participants. Questions were visible to all users after the IA submitted their response. For all other questions during this time, MPs were directed to the Message Board. The intended uses of the Q&A page and Message Board were explicitly stated in both the written and video tutorials, and were displayed on their respective pages. After October 9, 2018, the Q&A page was disabled and all communication between the IA and MPs occurred on the Message Board. All posts on the Q&A page remained visible to registered users for the entirety of the Tranche 1 process.

On the DEC Silo, 34 MPs asked a total of 172 questions on the Q&A page between April 6, 2018 and October 9, 2018. 14 MPs asked one question, and one MP asked 31 questions. In DEP during the same period, seven MPs asked a total of 22 questions on the Q&A page. Figures 8 and 9 below show the percent of total Q&A posts shown by individual MPs on the DEC and DEP Silos.

Figure 8

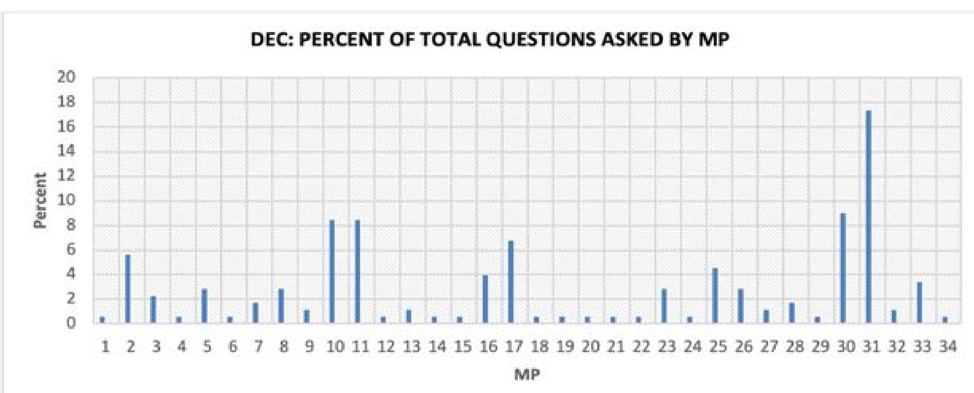
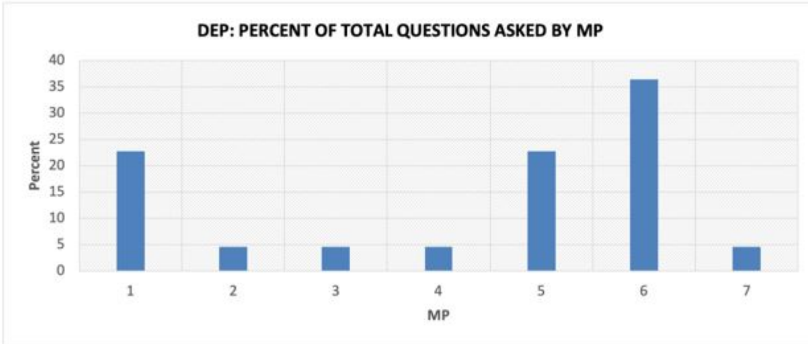


Figure 9



C. BIDDER WEBINARS/CONFERENCES

A Pre-Bid Conference ("Webinar" or "Conference") was held on May 17, 2018 for which participants were invited to register and participate in the Webinar by going to the RFP Website, logging onto the first Silo (DEC) and selecting the "Pre-Bid Webinar" tab on the menu bar.

The following announcement was posted on the RFP Website on May 8, 2019 announcing the Pre-Bid Conference:

From: decpre@acciongroup.com
To: [Website Registrant]

Subject: Duke Energy Carolinas - Announcement Posting
Please do not reply to this auto-generated email.

An announcement has been posted on the Duke Energy Carolinas website. Information about the announcement follows:

Reference #: 3
Date Posted: 5/8/2018 1:37:33 PM

Announcement:

The Independent Administrator and Duke will present the CPRE RFP webinar for interested persons on Thursday, May 17, 2018, beginning at 8:30 am (Eastern). To register for the webinar, visit the RFP website https://decprerfp2018.accionpower.com, and log onto the first silo – Duke Energy Carolinas CPRE RFP – 600 MW and select the "Bidder Webinar" on the menu bar.

If you would no longer like to receive these announcement notifications, click the link below.

Unsubscribe
https://decprerfp2018.accionpower.com

Figure 10

States Represented	Attendees
Arizona	1
California	10
Colorado	2
District of Columbia	1
Florida	9
Georgia	2
Illinois	5
Indiana	1
Minnesota	2
Nevada	1
New Jersey	1
New York	1
North Carolina	44
Ohio	1
South Carolina	5
Tennessee	7
Texas	5
Virginia	2
Washington	1
Total	**101**

Upon successful registration on the RFP Website for the Webinar, registrants received confirmation of their registration and notification that Webinar call-in details would be emailed to everyone who registered within 24 hours before the Webinar.

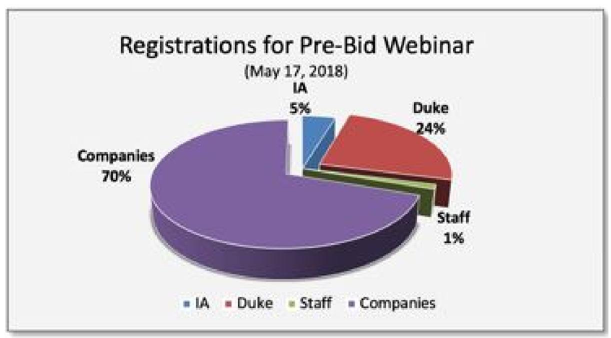
One hundred twenty-five (125) individuals registered to attend the Pre-bid Webinar representing 60 Companies from 19 states.

A detailed breakdown showing states represented is displayed in Figure 10.

Of the total registrants, 21 were from Duke Energy, four were from the IA Team and one Staff member registered. One hundred one (101) individuals of the 125 registrants actually signed in to participate in the Webinar. Figure 11 shows the breakdown of individuals who registered to attend the Pre-Bid Webinar.

While registrants were encouraged to pre-register for the Webinar, and reminders were sent to encourage registration, no individual was ultimately denied access to participate in the Webinar. The Webinar Access information was also posted on the Announcement page prior to the start time to accommodate those who had not registered but wished to participate. Twenty (20) individuals registered after the Webinar had commenced.

Figure 11



The presentation slides created for the Webinar were posted on the RFP Website prior to the Webinar on May 16, 2017, for the benefit of all registrants and potential MPs, and additionally a recording of the entire program was posted on the Website following its completion, in order to provide all information for those unable to participate in the Webinar.

During the Webinar Duke and the IA provided background of the solicitation and an overview of the RFP process. The Webinar provided the participants with information on the following topics:

- Registration on the RFP Website
- Overview and Background
- HB 589 “Competitive Energy Solutions Law” for North Carolina
- CPRE Overview
- Information about the IA and the IA’s role
- Communications protocols

- Standards of Conduct/Expectation of MPs
- Tranche 1 Capacity and Schedule
- Proposal Requirements/Types accepted
- Evaluation Process
- Interconnection
- Pro Forma and Storage
- Asset Acquisition Proposals
- RFP Website and Video Tutorials

Finally, the participants were given an opportunity to ask questions. The Webinar produced thirty-nine (39) questions, which were answered by Duke Personnel or the IA. All responses from Duke were reviewed by the IA. The questions and written responses were posted on the CPRE Tranche 1 RFP Website on May 30, 2018. Participants were advised that the written responses should be used when preparing Proposals, as the oral response at the Pre-Bid Webinar may have been incomplete.

VII. PROPOSAL SUBMISSION

A. SUBMISSION PROCESS

On July 10, 2018, the Proposal Management page, which served as the homepage for all Proposals, was released to registered MPs. Upon its release, an announcement was made on the Website, and was also sent via email to all registered participants. [11]

The Proposal Management page allowed MPs to manage their Proposals from start to finish. Features of this page included the ability, to start, edit, clone, submit, or delete Proposals. They could also manage uploaded documents, change notification settings, and generally monitor the status of their Proposals. These features were explained in detail in both the written and video tutorials.

The Proposal submission deadline was on October 9, 2018, giving MPs nearly three months from the release of the Proposal form to submit a Proposal. The IA estimated that it took a minimum of one to three hours to complete the Proposal form if all document uploads were previously assembled. The IA therefore stressed to MPs the importance of starting Proposals well in advance of the submission deadline. Announcements were posted on August 6, 2018, and September 28, 2018 notifying MPs of this guidance.

[11] Users received email notifications of announcements automatically, however this setting could be turned off in their User Profile. Users who turned off email notifications did not receive notification of the release of the Proposal Management page.

Figure 12: Announcement from the IA reminding MPs to allow at least 3 hours to complete Proposal form

9/28/2018 9:11:23 AM	As a reminder, the DUKE CPRE proposals are due on Tuesday, October 9, 2018, at noon EPT. The Market Participants ("MPs") **should allow at least 3 hours** to complete the proposal form, ***after*** assembly of required documents for upload as well as all required information. A copy of the proposal form is provided on the document page as a worksheet to assist in assembling proposal information. MPs are reminded that all proposal must be priced below avoided cost. The MP is to enter one value on the proposal form and the website will automatically calculate and present the price for each period. MPs are encouraged to complete and submit their proposal form on time if they intend to participate in the Duke CPRE RFP process because late proposals will not be accepted. Please CLICK on the submit button once you complete the proposal form. (Ref.# 18)

The electronic submission process provided MPs with several features which aimed to streamline the bidding process. First, all uploaded documents were automatically saved and organized into a Proposal folder system. Second, if an MP submitted an incomplete Proposal, a PDF version of the Proposal form appeared as currently completed with all incomplete fields highlighted in red. Finally, MPs could clone a Proposal at any time. Cloned Proposals created a new Proposal with identical information from the original; this feature allowed MPs who wished to submit similar, but not identical Proposals an the ability to duplicate relevant data with a single click.

B. PROPOSAL SUBMISSION REQUIREMENTS

1. Avoided Cost Thresholds

The CPRE program solicited resources that were priced below administratively-established avoided costs. The RFP provided avoided cost rates for three pricing periods: Summer, Non-Summer, and Off Peak, to which all Proposals must have bid at or below. The following are the charts of pricing periods taken from the RFP.

Figure 13

Transmission Connected Projects				
Avoided costs ($/MWh)	DEC		DEP	
	Summer	Non-Summer	Summer	Non-Summer
Capacity + Energy On Peak	$58.00	$74.90	$57.40	$78.20
Energy Off Peak	$36.40		$35.70	

Figure 14

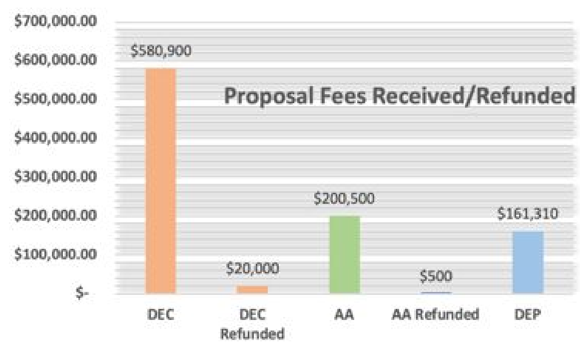
Distribution Connected Projects				
Avoided costs ($/MWh)	DEC		DEP	
	Summer	Non-Summer	Summer	Non-Summer
Capacity + Energy On Peak	$59.40	$76.70	$58.50	$79.70
Energy Off Peak	$37.20		$36.20	

2. Proposals Fees

Each MP in this RFP was required to pay a non-refundable "Proposal Fee" with each Proposal submitted based on the facility's nameplate capacity. For PPA Proposals, a minimum fee of five hundred dollars ($500) per MW with a maximum of ten thousand dollars ($10,000) was due at the time each Proposal was submitted. For Asset Acquisition Proposals, a non-refundable minimum Proposal Fee of ten thousand dollars ($10,000) was due for BOT and Joint Venture Proposals.

Proposal Fees were automatically calculated using the nameplate capacity entered on each Proposal Form, and instructions for electronic payment were provided both on the Proposal Form, and additionally on the RFP Website documents page. Failure to submit the Proposal Fee resulted in automatic disqualification of the Proposal from further consideration.

Figure 15



The IA received and reconciled all Proposal Fees with corresponding Proposals and confirmed that all fees were paid and received no later than 12:00 PM EDT (Noon) on the Proposal due date, as directed by the RFP Documents. The total amount of Proposal Fees received was $922,710. Figure 15 shows the breakdown of fees received for DEC, DEP and AA Proposals submitted, including all refunded Proposal Fees. During the reconciliation process, the IA reached out via the Message Board to one DEC MP who failed to complete and submit two Proposals but paid both Proposal Fees, and one AA MP who overpaid their Proposal fee. Upon confirmation from both MPs the IA refunded the $20,000 Proposal Fees for the unsubmitted Proposals and the $500 overpayment.

Fees were not refunded in the case of any modification of the RFP schedule, rejection of any Proposal, or failure by a winning MP to execute a PPA.

C. PROPOSAL SUBMISSION STATISTICS

1. Submission

Most MPs submitted more than a single Proposal. In DEC, 10 of the 18 bidding MPs submitted more than one Proposal. In DEP, three MPs submitted only one Proposal while seven of 10 bidding MPs submitted more than one Proposal. Eight MPs submitted only one Proposal in DEC, while one MP submitted 15. The average number of Proposals submitted by an MP was three in DEC and two in DEP.

Figure 16

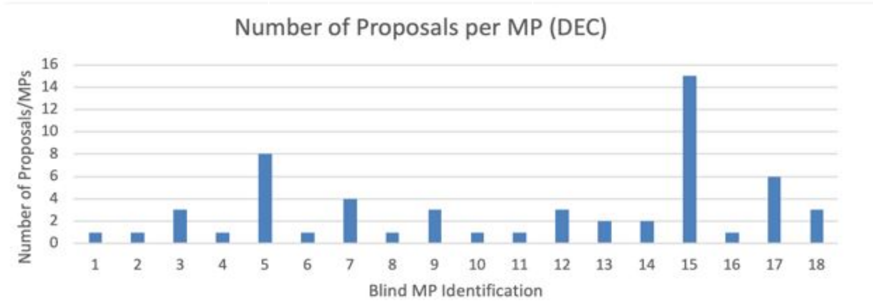
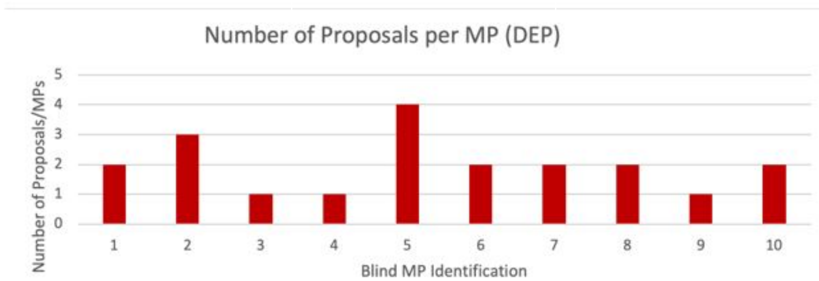
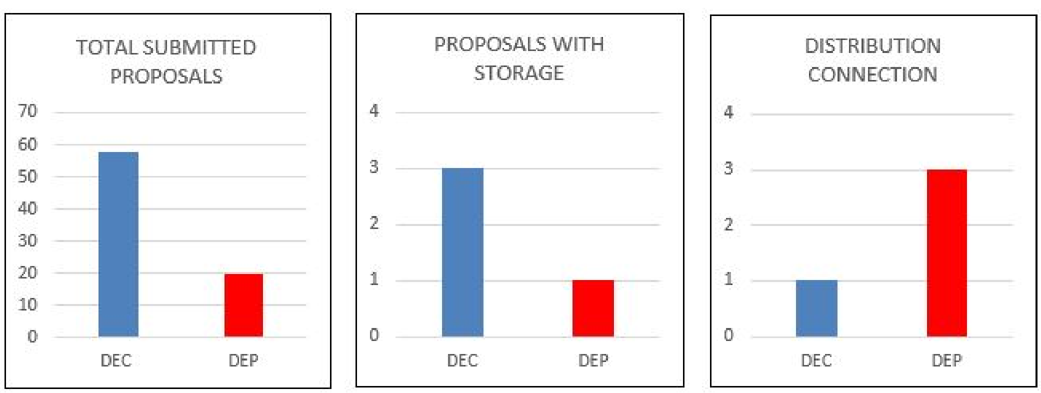


Figure 17



Both DEC and DEP had a robust number of Proposal submissions; DEC received 58 Proposals and DEP received 20. All Proposals were for solar photovoltaic generation. Three Proposals were submitted with energy storage systems integrated with PV systems in DEC, while one Proposal did the same in DEP. One Proposal would interconnect to the distribution system in DEC, and three would do the same in DEP; the remaining Proposals on each Silo required transmission system interconnection.

Figures 18, 19, 20

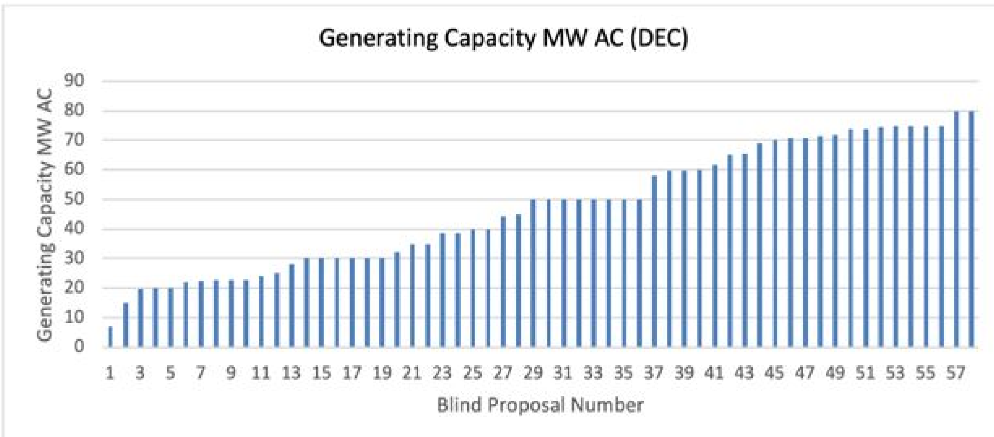


2. Generating Capacity

Duke Energies Carolina (DEC)

DEC received more than four times the targeted 600 MW for CPRE Tranche 1. Proposals were submitted with between seven and 80 MW of generating capacity, and totaled 2732.72 MW. The average Proposal was submitted with 47.16 MW of generating capacity.

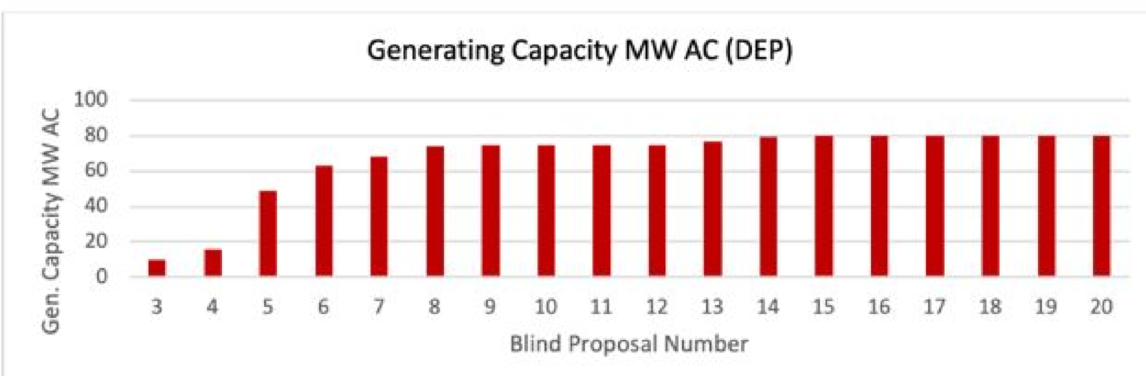
Figure 21



Duke Energies Progress (DEP)

DEP received more than 15 times the targeted 80 MW for CPRE Tranche 1. Proposals were submitted between 7.02 and 80 MW of generating capacity, and totaled 1,231.15 MW. The average Proposal was submitted with 61.55 MW of generating capacity.

Figure 22



3. Transmission and Distribution

A goal of CPRE was to have "shovel ready" projects move forward by using available transmission and distribution resources. [12] MPs were required to identify the Point of Interconnection (POI) to which their project would connect, as well as whether the MP desired distribution level or transmission level service. All projects 20 MW and larger were required to have interconnection at transmission level. Projects sized smaller than 10 MW were required to have connection at distribution level. Projects sized 10 MW to 19 MW could interconnect at transmission level, but to maximize use of existing capacity for were assigned to the distribution system. A significantly higher number of MPs proposed to interconnect at the transmission level than to the distribution. In DEC, 57 Proposals sought transmission interconnection while only one sought distribution interconnection. In DEP, 17 Proposals sought transmission interconnection while only three sought distribution interconnections.

Figure 23

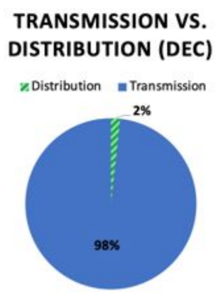
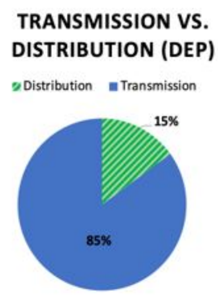


Figure 24



4. Submission by State

Pursuant to the CPRE requirements, all proposed facilities for DEC and DEP were required to be located in the respective DEC or DEP service territories. There were a total of 33 DEC Proposals totaling 1415.91 MWs and a total of 9 DEP Proposals totaling 617.3 MWs in North Carolina. In South Carolina, there were a total of 25 Proposals totaling 1316.81 MWs in DEC, and a total of 11 Proposals totaling 613.89 MWs in DEP. The IA believes Tranche 1 received a balanced load of Proposals between North Carolina and South Carolina.

Figure 25

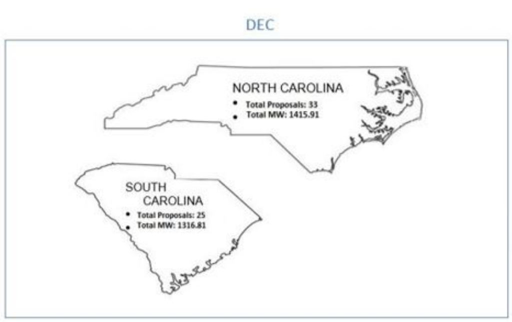
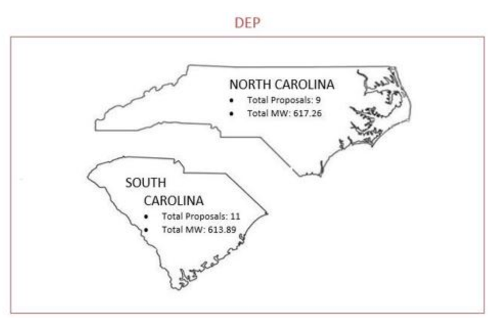


Figure 26



[12] In furtherance of this goal, in Tranche 1 projects that had completed interconnection studies and committed to pay the cost of interconnection were recognized as "Late Stage" Proposals and were excluded from the cluster study process. Thus, the Late Stage projects were recognized as being "shovel ready" and given priority during the Step 2 evaluation process.

VIII. EVALUATION MODEL

A. OVERVIEW

Each Proposal was evaluated using the MP's pricing information (with three price tiers of decrement), the facility's MW AC generating capacity, and the MP's hourly production profile over 20 years ("Loadshape") information. For proposals that included storage, the facility storage parameters (nominal output, storage duration, and charging rate), and production profiles with and without storage were included in the evaluation.

The IA created a custom evaluation model based on prior experience and the needs of the CPRE program ("Evaluation Model") which utilized the bid input parameters to calculate each Proposal's benefit ("Net Benefit") to the Company system over the twenty-year PPA term. A Proposal's Net Benefit is the sum of the facility's net energy benefit and the facility's capacity benefit, less the costs of system upgrades required to interconnect the facility.

Net Benefit ($/MWh) = Net Energy Benefit ($/MWh) + Capacity benefit ($/MWh) - T&D ($/MWh)

In Step 1, the proposals were ranked based on the net energy and capacity benefits, excluding T&D system upgrade costs. In the Step 2 process, the T&D system upgrade costs for projects were calculated in an iterative process starting with the most attractive proposals and then imputed to the Proposal in the final ranking of Proposals.

B. REQUIRED INPUT DATA

1. Loadshape 8760

For each Proposal, the MP was required to supply a 20-year 8760 Loadshape that best represented the long-term output of the facility. The 8760 Loadshape was subject to review by the Independent Administrator to ascertain that the data within the Loadshape does not exceed the capability of the proposed facility.

A Proposal that included storage was required to submit a pre-storage Loadshape as well as the post-storage Loadshape. The pre-storage Loadshape represented the facility generation with the storage capability turned off. The post storage Loadshape represented the MP's best effort to utilize the facility with its storage capability to maximize facility value (but remain within the practical limits of the energy storage capability). The pre-storage Loadshape was compared to the post-storage Loadshape to evaluate whether the MP exceeded the limits of his Proposal's storage capability in submitting the post-storage Loadshape. The evaluation of a Proposal that included storage was based upon the post-storage 8760 20-year Loadshape data.

A Proposal that did not include storage was required to submit the single 20-year 8760 Loadshape which was used in the evaluation of the facility.

2. Facility Pricing

The CPRE program required that each Proposal was priced as a decrement (i.e., below) the levelized 20-year avoided cost identified in the RFP. This decrement was a single $/MWh amount that applied to each avoided cost pricing period. Once a single decrement amount was entered, the Website automatically converted the decrement into a price that would be below avoided costs for each of Duke's avoided cost price periods. The Proposal form prevented the entry of pricing above Duke's avoided costs. The Website Proposal form presented the calculated prices for each pricing period so the MP could confirm the pricing Proposal was as desired. As noted above, after the Proposal submission period closed, the IA provided each MP with a summary of their respective Proposal(s) and received a confirmation from each MP that the pricing was as intended.

The Avoided Cost rate was a three-tier rate which covers:

a. Summer Peak – the non-weekend and non-holiday hours between 1:00 PM and 9:00 PM during the months of June through September.

b. Non-Summer Peak – the non-weekend and non-holiday hours between 6:00 AM and 1:00 PM during the months of October through May.

c. Off-Peak – all weekend and holiday hours as well as weekday/non-holiday hours that fell outside of the 8 hour "Summer Peak" band during the months June through September and those weekday/non-holiday hours that fell outside of the 7 hour "Non-Summer Peak" band during the months October through May.

MP pricing was submitted as a decrement to the appropriate forecasted Avoided Cost rate which differed for transmission/distribution connection as well as balancing area (DEC or DEP). The minimum acceptable decrement was zero, which replicated the forecasted Avoided Cost rate.

There was a range of price decrements submitted. The median price decrement for Proposals submitted in both DEC and DEP was 6.73 $/MWh.

3. Other Required Inputs

a. In addition, evaluation of each facility included the following data:

b. Inverter Capability

c. Interconnection (Distribution or transmission) Voltage

d. Storage Capability (if applicable) in MW nominal output

e. Storage Capacity (if applicable) in Hours duration at the nominal output

f. Maximum Storage charging rate in MW (if applicable)

The inverter capability represented the maximum output from a project as submitted on each 8760. The interconnection voltage was included in the modeling to determine the energy that could flow from the facility.

C. EVALUATION MODEL PROCESSING

The first iteration of the evaluation model calculated for each proposal the capacity benefit, the energy benefit, and the Proposal cost on a year-by-year basis by using the MP's pricing information for the three price tiers, the inverter capability, the basic storage parameters (nominal output, storage duration, and charging rate) if storage is included, and the MP's Loadshape information. During the second iteration of the evaluation model, the after-curtailment, and, if appropriate, the after-storage benefit was calculated. Finally, the Proposal was evaluated on its twenty-year net present value of benefit per MWh which was used by the IA for ranking Proposals.

The evaluation model processing routine included these key elements:

1. **Pricing: Assign Periods and Generate 20 year $/MWh**

Each hour within the single 8760-hour year was assigned to one of the three pricing tiers (see "Facility Pricing" above) and an energy price was also assigned. This was repeated for all years until each hour of the twenty years of Loadshape data was assigned an energy price. Adjustments were made as required for holidays and weekends, daylight savings time shift, and leap year calendar effects.

2. **Capacity Benefit Calculation**

The facility's capacity benefit is the cost savings associated with the proposed facility's ability to defer future generating capacity on the Duke system. Each year of the production profile (8760) input data was compared against a Loss of Load Expectation ("LOLE") matrix that measured a facility's ability to generate electricity during periods of critical need for the grid. The facility's resulting capacity benefit was estimated by comparison to the Duke system (DEC or DEP) avoided cost. The benefit was estimated by using the system's avoided capacity cost (on a $/MW basis projected from the future cost of utility constructed supply side peaking generation) and allocated to that facility.

3. **Net Energy Benefit Calculation (Energy Benefit less Proposal Cost)**

The Net Energy Benefit was calculated as energy savings to Duke Energy resulting from the operation of the proposed facility. The energy savings for a facility was the difference between the Duke Energy marginal energy cost and the proposed facility's energy cost (as established by the MP's submitted pricing). This analysis was run on an 8760 hour per year basis for twenty years. In any hour that the facility generates energy, the energy savings for each hour would be the facility output multiplied by the difference between the Duke marginal energy price and the facility energy price. This was conducted in an iterative process to incorporate the impacts of curtailment and storage (if included).

IX. EVALUATION

A. OVERVIEW OF EVALUATION PROCESS

The IA strictly followed the evaluation protocol set forth in the Tranche 1 RFP and in NCUC Rule R8-71(f)(3). Further, all appropriate evaluation process information was communicated to MPs in a timely manner. The IA composed a flow chart depicting the entire process, which was then discussed with the Companies and shared on the Website for the MPs on September 19, 2018. Further, the Announcements, Messages, and Schedule pages were monitored daily to reflect the current Tranche 1 plan, or to remind MPs of an upcoming evaluation deadline.

The major components of the evaluation process are described in depth below. The process was designed to evaluate each Proposal individually while maximizing efficiency and fairness. The IA believes this process succeeded in this goal, and all refinement suggestions for Tranche 2 remain minor.

B. PRICE SCORING SHEETS

In accordance with the Appendix F of the RFP, the Price Scoring Sheet ("Scoring Sheet") was used to when reviewing each Proposal. The Scoring Sheets allocated weighted scores to each evaluation category, and category scores were summed to reach a Proposal's overall evaluation score. This method confirmed that each Proposal was evaluated using the same criteria. An example of a Scoring Sheet is attached as Appendix A.

C. EVALUATION TEAMS

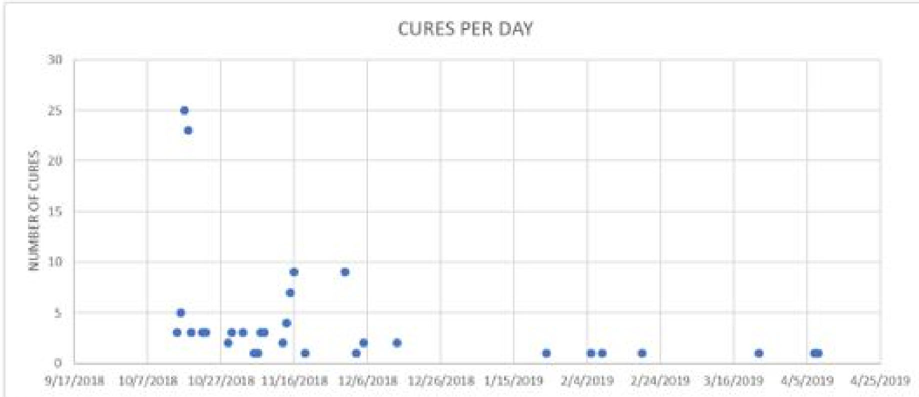
The IA created five subject matter evaluation teams: Modeling ("Modeling"), Financial ("Financial"), Legal ("Legal"), Transmission & Distribution ("T&D"), and Engineering/Project Sufficiency ("PST"). Each team contained subject matter experts and focused their work on their respective portions of the Proposal evaluation. Each of the teams used their designated sections of the Scoring Sheet as the basis of their evaluation. The Modeling Team designed and created the Evaluation Model and worked to determine the "Price Score" defined on the Scoring Sheet. The Financial Team determined the "Credit Worthiness" score for each Proposal by evaluating the MP's financial assurances and credit requirements. The Legal Team focused on three areas: determining that the MP could complete permitting to meet COD, determining that the Proposal had project site control for full term, and determining that the Proposal had site control to the POI for full term. The PST determined scores for four categories: experience of the project team, equipment to be used, required control equipment, and quality of project design. Finally, the T&D Team worked to assist the Modeling Team in determining the Price Score of each Proposal by conducting the T&D analysis of system upgrade costs as described below in Section XI.

D. CURE PROCESS

After Proposals were submitted, it was necessary to fix any inaccuracies made by MPs, and to gather any further materials requested by the IA's evaluation team. This process ("Cure Process"), cures occurred at the beginning stages of Step 1. In a few instances, the IA sought information from MPs when Proposals were moved from the reserve list and to the competitive tier, after the start of Step 2. The number of cures per day is shown in Figure 27. Together there were 125 cures in DEC and DEP throughout the evaluation process, with an average of 1.5 cures per Proposal. [13] The Cure Process confirmed the data inputted on the Proposal Forms to be correct and ready for evaluation. It is worth noting that the initial identification of deficiencies with Proposals, immediately after their receipt, obviated the need to delay evaluation later during the iterative process of elevating Proposals from the Reserve List to the Competitive Tier.

[13] Includes all cures/clarifications directly related to the characteristics of the proposal. This does not include cures for other aspects of the evaluation process, such as Proposal security Forms.

Figure 27: Number of cures per day over the evaluation process



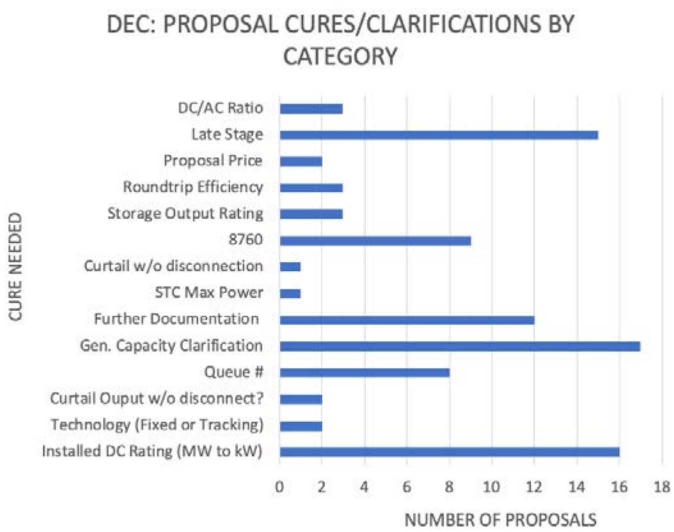
The Cure Process immediately followed Proposal submission on October 9, 2018, with each Evaluation team performing an overview analysis of the data pertaining to their expertise. If any questions were raised or clarifications required, an MP was notified via the Message Board and was given an appropriate amount of time to respond. In total, 48 of the original 58 DEC Proposals and 14 of the original 20 DEP Proposals submitted cures at some point during evaluation.

Most of the cures were identified and accomplished using the Confirm Bid Data Memorandum ("Confirm Bid Data Memo", or "Memo") created by the IA. On October 16, 2018, the IA sent a Memo to the MP of each Proposal with the following information:

- Technology
- Generating Capacity MW AC
- Installed DC Rating [kWpDC]
- Is Storage Included?
- Storage Size (MW)
- Storage Output Rating (MW)
- Price Decrement
- Summer Decrement
- Non-Summer Decrement
- Off-Peak Decrement
- Forecasted COD
- Curtail Output Without Disconnecting?
- Offering to Reduce MW size for Same MWh?
- MW Reduction Amount up to 10%
- Late Stage Proposal?

These Memos resulted in MPs identifying 31 DEC Proposals and 13 DEP Proposals that required cures. MPs were required to respond to the Memo with either confirmation of correct data or identification of inaccurate data. If an MP did not respond, the IA interpreted all data to be correct and evaluated as such. Following the Memo correspondence, alterations of data in these categories was prohibited.

Figure 28



1. DEC

In total, 102 cures/clarifications were made in DEC. 94 of the 102 cures were made during the Step 1 evaluation. The most requested cure by the Evaluation Team was the Generating Capacity of the facility. This is likely linked to confusion on the Proposal Form regarding the difference between inverter capacity and generating capacity as it applies to overall generation, and will be clarified for Tranche 2. Further, many Proposals used "MW" units when the Proposal Form indicated "kW." All cure categories and frequencies are depicted in Figure 28.

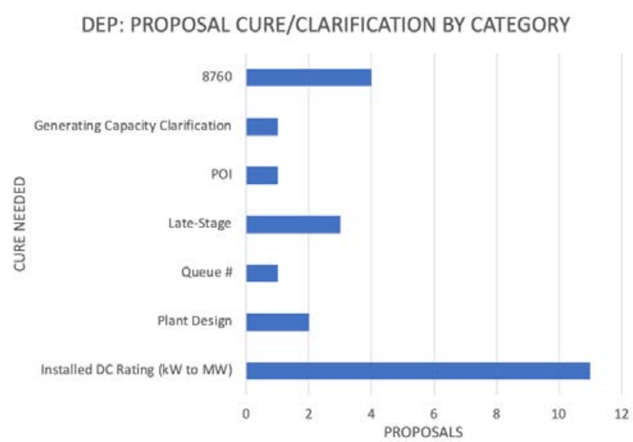
Most Proposals were submitted with no need for major adjustments. 62% of Proposals required no cures (10) or had only one cure (26). Three Proposals, all from the same MP, required eight cures.

2. DEP

In DEP, 23 cures were made. The Step 1 evaluation accounted for 22 of these cures. The most requested cure by the evaluation team was to change the units of the Installed DC Rating from MW to kW as requested on the Proposal Form. All cure categories and frequencies are depicted in Figure 29.

Most DEP Proposals were submitted with no need for major adjustments. 57% of Proposals required no cures (6) or had only one cure (7). Two Proposals required three cures.

Figure 29



X. STEP 1 EVALUATION PROCESS

A. OUTLINE OF PROCESS

The goal of the Step 1 evaluation was to categorize Proposals into three Tiers: The Primary Competitive Tier, the Competitive Tier Reserve, and the release list, ranked in order from most attractive to least attractive for ratepayers prior to the Step 2 T&D evaluation. The Tiers were constructed based upon two metrics: The Net Benefit ($/MWh) of each Proposal calculated by the Evaluation Model, and the cumulative generating capacity MW AC.

The Tier structure was created by the IA for the benefit of the MPs. In the Step 1 evaluation, Proposals were sorted based on the overall benefit to ratepayers prior to the Step 2 T&D evaluation of system upgrade costs. This allowed only Proposals with the highest likelihood of being selected as a winner being included in the Primary Competitive Tier and therefore required to post Proposal security. The Competitive Tier Reserve included Proposals with a lower likelihood of being selected for a PPA. A Proposal on the Reserve Tier remained in the CPRE program, but was not required to provide Proposal security until notified that the Proposal was eligible for evaluation in Step 2. Proposals in the Competitive Tier Reserve were moved into the Primary Competitive Tier when other Proposals dropped out due to declining to provide Proposal security, or were found to be above Avoided Cost during the iterative Step 2 evaluation, necessitating adding additional MWs to the Step 2 evaluation in order to meet the Tranche 1 goals.

The composition of each Tier at the end of Step 1 ("Initial Tier Ranking") was completed on December 6, 2018. On that date, a memo was uploaded to each Proposal's Cure Folder with the Proposal's initial status. Further, the IA published the "CPRE Tranche 1 Initial Status Report" for public viewership on the IA Website on December 7, 2018.

The final phase of the Step 1 evaluation required all Primary Competitive Tier Proposals to provide Proposal security. If an MP declined, their Proposal was released from CPRE. This allowed the IA to filter out uncommitted Proposals outright before having to undertake a time-consuming T&D evaluation in Step 2. Once an MP provided an acceptable form of Proposal security, the IA notified the T&D Team to begin evaluation of the Proposal, thus beginning the Step 2 evaluation of the Proposal.

B. INITIAL TIER RANKING

1. Primary Competitive Tier

The Primary Competitive Tier was composed of Proposals with the highest Net Benefit ($/MWh) as determined by the Evaluation Model before considering T&D system upgrade costs. The IA's goal was for the Primary Competitive Tier to contain two times the MW goal in each Silo, thus allowing for the elimination of some Proposals while still meeting the intended MW goal. This also allowed the IA to continue evaluation of Proposals beyond the original goals without a delay as new Proposals were asked to post security. Each Proposal received a memo regarding its Initial Tier Ranking status at the end of Step 1. In line with the RFP standards, MPs were given seven business days following notification of Primary Competitive Tier status to provide Proposal security in the amount of $20/kW.

CPRE is a multi-year procurement program, with the goals of Tranche 1 designed to begin the competitive procurement process. Tranche 1 had a goal of 600 MW for DEC and 80 MW for DEP. The DEC Initial Primary Competitive Tier contained 24 Proposals totaling 1270.22 MW. All Proposals selected for the Competitive Tier were bid in with a price decrement at least 8.9 below avoided cost, and with an average price decrement 12.36 below avoided cost. Following the Evaluation Model calculation, the estimated Net Benefit of Proposals was at least $6.48/MWh, and averaged $9.94/MWh. All Proposals selected were highly competitive and provided significant value to ratepayers.

The DEP Initial Primary Competitive Tier contained eight Proposals totaling 469.52 MW. The MW goal for DEP was 80 MW, thus the 469.52 MWs selected far exceeded the two-times MW goal. As stated above, this target goal was created to ensure that enough MPs would supply Proposal security and maintain their initial value to begin the Step 2 T&D evaluation. Because the DEP MW goal was smaller than that of DEC (80 MW vs. 600 MW), individual Proposals in DEP represented a larger fraction of the MW targeted goal than those in DEC. In fact, several Proposals in DEP were bid with a generating capacity equal to the MW goal. For this reason, the IA chose to include Proposals representing a greater MW total than in DEC in the Initial Tier Ranking for DEP.

All DEP Proposals selected in the Initial Tier Ranking were bid in a price decrement at least 7.1 below avoided cost, and with an average price decrement 14.01 below avoided cost. Following the Evaluation Model calculation, the estimate Net Benefit of Proposals was at least 5.58 $/MWh and averaged 10.35 $/MWh. All Proposals selected were highly competitive and would potentially provide value to ratepayers.

Figure 30

Primary Competitive Tier Proposals			
	Total MWs	Average Price Decrement below Avoided Cost	Average Net Benefit
DEC	1270.22	12.36	9.94 $/MWh
DEP	469.52	14.01	10.35 $/MWh

2. Competitive Tier Reserve

The Competitive Tier Reserve contained the next best Proposals in the Net Benefit ($/MWh) ranking determined by the Evaluation Model, and equaled one times the MW goal for each Silo. Proposals selected for this Tier were considered competitive Proposals with the potential to be selected as Finalists, however the MPs were not required to post Proposal security at the time of the Initial Tier Ranking. This Tier was created by the IA specifically to benefit MPs by limiting the financial burden associated with Proposals less competitive than the best-ranked Proposals, but still considered viable for future consideration.

The DEC Competitive Tier Reserve contained 10 Proposals totaling 543.84 MW, which complied with the one-times the MW goal standard for Tier size. All Proposals selected had a price decrement that was at least 6.38 below avoided cost, and had, on average, a price decrement 7.04 below avoided cost. Following the Evaluation Model calculation, the estimated Net Benefit for Proposals was at least 4.0 $/MWh, and on average 4.91 $/MWh. These Proposals were still highly competitive, and would potentially provide value to ratepayers.

The DEP Competitive Tier Reserve contained eight Proposals totaling 612 MW. The IA selected more than the MW size goal for this Tier for the same reasons it over-selected in the Primary Competitive Tier. All Proposals selected had a price decrement at least 4.67 below avoided cost, and on average had a price decrement 5.93 below avoided cost. Following the Evaluation Model calculation, the estimated Net Benefit for Proposals was at least 0.94 $/MWh and averaged 2.2 $/MWh. All of the Proposals remained below the avoided cost threshold.

Figure 31

Competitive Tier Reserve Proposals			
	Total MWs	Average Price Decrement Below Avoided Cost	Average Net Benefit
DEC	543.84	7.04	4.91 $/MWh
DEP	612	5.93	2.2 $/MWh

3. Release List

The release list contained the least competitive Proposals. MPs with Proposals selected to the release list had the option to keep their project in CPRE by being included on the Reserve Tier. The table below depicts the response of MPs with Proposals when notified that their Proposal was identified for release, but could be on the Reserve Tier.

Figure 32

Silo	Release List Proposals	Proposals Moved to Reserve from Release
DEC	23	23
DEP	3	2

C. PROPOSAL SECURITY

1. Overview

Proposal security was required from all third-party MP Proposals. As per the RFP, Proposal security equaled \$20/kW, based on the facility's inverter nameplate capacity. Proposal security was required within seven business days of MP's notification of a Proposal's selection for the Primary Competitive Tier. The Proposal security was accepted as cash, a Surety Bond, or a Letter of Credit ("LOC"). The IA provided acceptable Surety Bond and LOC forms on the IA Website as part of the RFP.

Third-party MPs had the option to withdraw their Proposal by not posting Proposal security. If an MP did not post Proposal security within the seven-business day window, the IA confirmed via the confidential Message Board that the MP intended to withdraw the Proposal from consideration. This discouraged the withdrawal of Proposals during the final contracting stages of Tranche 1 and encouraged only "shovel ready" projects to seek Step 2 review. This procedure was consistent with the design of CPRE so Tranche 1 ended with the identification of finalists by the IA, and all other Proposals would be released so the unsuccessful MPs would have their Proposal security released to be available for other projects. Additionally, the use of Proposal security greatly increased the likelihood of PPAs being executed, in contrast to what has occurred in other jurisdictions when developers are permitted to withdraw at the 11th hour.

As projects were eliminated or withdrawn from the Primary Competitive Tier, the IA proceeded to move additional Proposals into the Primary Competitive Tier; these selections were made based on the Initial Tier Ranking. When a Proposal was selected to advance to the Primary Competitive Tier, the IA notified the Proposal MP via the confidential Message Board and advised the MP of the seven-business day deadline for Proposal security (sometimes referred to as "bid security"). The following is an example of a message sent in this instance on the Website:

> *Proposal [X] has been moved from the reserve list to the primary competitive tier. In order to proceed, the MP must now provide the bid security for this project, as identified in the RFP. Please use the "upload documents" feature on the message board to provide the security bond or another acceptable form of security.*

The MP should use the message board to advise the IA if the security will be in the form of cash and IA will provide instructions. To facilitate timely evaluation of the proposal the security should be received without delay, preferable by COB on February 7, 2019. Pursuant to the terms of the RFP, the security must be provided no later than February 12, 2019.

All Proposal security forms were uploaded by MPs to the Cure Documents folder within the Proposal Books on the IA Website. Upon submission, the IA confirmed the validity of the file and sent the relevant documents to the Duke Legal Team for review. If the Duke Legal Team declared the form to be insufficient, the IA allowed the MP to make the appropriate revisions. Below is a message by the IA to an MP in such a case:

Duke personnel has reviewed the security form for this proposal and found two deficiencies. Please revise the document in two business days, by end of COB, Friday, February 15, 2019, and post the document using the "upload documents" button on the message board of the RFP website.

The deficiencies are: 1. surety bond effective date is in brackets. 2. Date of CPRE in first recital is shown as May 11, which is incorrect.

Needed cures: 1. remove brackets around the effective date on the first page. 2. Change the issuance date (on the bottom of the first page) from May 11, 2018, to July 10, 2018.

Once a Proposal's security was accepted by the Duke Legal Team, the Proposal was moved from Step 1 evaluation to Step 2 T&D review.

2. DEC

Within the DEC Initial Primary Competitive Tier, 60% of third-party Proposals declined to provide Proposal security. This resulted in only 15 Proposals totaling 833 MW left in the Initial Primary Competitive Tier for Step 2 T&D evaluation. The IA then advanced more projects into the Primary Competitive Tier. Using the Initial Tier ranking, the T&D Team completed preliminary evaluations of all Competitive Tier Reserve and Release List Proposals to determine the viability of each project before requesting Proposal security and moving them to Step 2 T&D evaluation. A Proposal was eliminated if: it did not have a queue number, it did not have a viable interconnection, or it was in a pre-identified constrained area and had a distribution factor above 3%. Seven Proposals were eliminated during this part of the evaluation process. Additionally, three Proposals identified as duplicates of higher-ranked projects and were removed from consideration.

In total, 22 of the 33 Proposals from the Competitive Tier Reserve or release lists were moved into the Primary Competitive Tier. Of those Proposals, four were submitted by Duke's Affiliated or DEP/DEC team and were sent to the T&D Evaluation team for Step 2 evaluation. The remaining 18 Proposals were required to provide Proposal security before advancing; 12 declined. The six Proposals which provided Proposal security were sent to the T&D Evaluation team for Step 2 evaluation. In total, 47 of the 57 DEC Proposals in the Initial Tier Ranking were moved to the Primary Competitive Tier at a point in time in the evaluation process. Of those 47 Proposals, 33 were third-party Proposals and were required to provide

Proposal security; 21 declined. Ultimately, a total of 26 Proposals were sent to the T&D Evaluation team for Step 2 evaluation.

3. DEP

The DEP Initial Primary Competitive Tier included eight Proposals, of which six were required to post Proposal security and one declined. The remaining seven Proposals totaled 394.62 MW, just under five times the DEP MW goal. The IA considered this to be a sufficiently robust set of Proposals and therefore did not move any further Proposals into the Primary Competitive Tier prior to the completion of Step 2.

XI. STEP 2 EVALUATION PROCESS - T&D OVERVIEW

The goal of the Step 2 evaluation process was to calculate the final Net Benefit ($/MWh) of each Primary Competitive Tier Proposal. The main burden of this step was on the T&D Team to assign an estimated upgrade cost to each qualifying proposal. The purpose of this section is to document the steps taken by the IA and the Duke T&D Evaluation team to complete the system upgrade cost analysis for each Proposal. [14] This work was completed at the end of May 2019. This discussion is presented as a chronology of events, from those actions taken prior to Proposal submission. From this process the IA developed recommendations for the T&D evaluators to be employed in Tranche 2.

A. ACTIVITY PRIOR TO PROPOSAL SUBMISSION

1. Portfolio Study Example

MPs expressed interest in learning more about the methodology the IA planned to use to complete the portfolio analysis. Such analysis was critical as multiple Proposals competed for the same network resources, thus necessitating allocation of line capacity between competing Proposals.

The IA prepared an example of its approach to portfolio analysis, based on previous engagements. This example was specific to the Duke CPRE process. In early September 2018, this example was reviewed with the Commission Public Staff and with Duke personnel. This review resulted in several modifications that better adapted the analysis for this project. The portfolio study example was finalized on September 19, 2018, and posted on the IA website Document page.

Separate Competitive Tiers were established for DEC and DEP by the IA and shared with the T&D Team to begin the Step 2 analysis. The Step 2 process included an analysis of potential electrical interdependency of these Proposals was performed. It was apparent from a review of the Points of Interconnection ("POI") specified by the MPs that several of the Proposals in the Competitive Tier were electrically interdependent. The potential system impact of interdependencies were identified as the system upgrade costs for each Proposal were determined. The maps below show the geographic location

[14] The Duke T&D Evaluation team members all completed the separation protocol training and executed a confirming affidavit. No member of the T&D Evaluation team had involvement with the development of any Proposal from the Duke Companies Proposal Team or any affiliate of DEC or DEP that submitted a Proposal.

of the selected projects, and there was no electrical interdependency among the final Proposals, thus, sharing of network upgrade costs between Proposals was not needed.

2. Transmission Guidance Provided to Bidders

The T&D Team created a locational guidance document for MPs to better understand the available transmission capability and assist them in selecting viable points of interconnection. This guidance is included as Appendix B and was part of a webinar presented on May 10, 2018. A copy of the materials was available on the Document Page of the IA Website.

Notwithstanding the locational guidance, several MPs proposed non-late stage facilities in areas that were identified as constrained. The IA will not speculate on why an MP would participate in CPRE knowing their project was in a constrained area and therefore would have transmission upgrade costs assigned. Figure 33 below is a map of all DEC Proposals and the pre-identified constrained areas. Figure 34 shows all winning Proposals in DEC. Note that all winning Proposals were outside of the constrained areas. One successful DEP Proposal will interconnect at transmission level service and is shown in Figure 35. This was a late stage project.

Figure 33

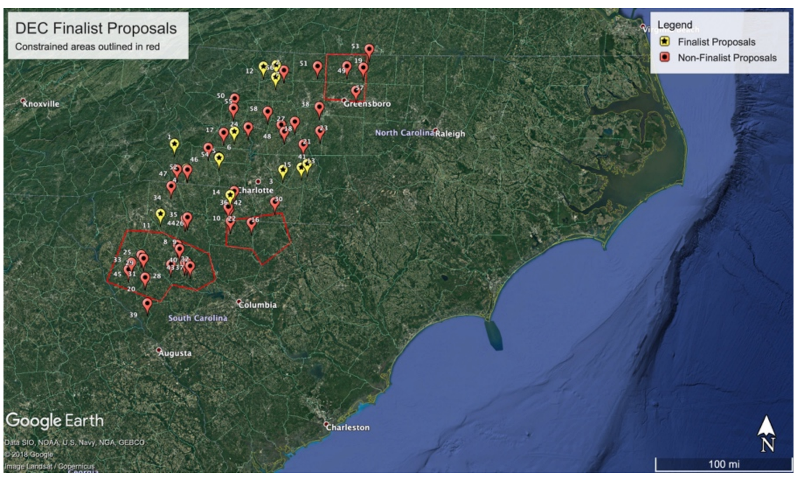
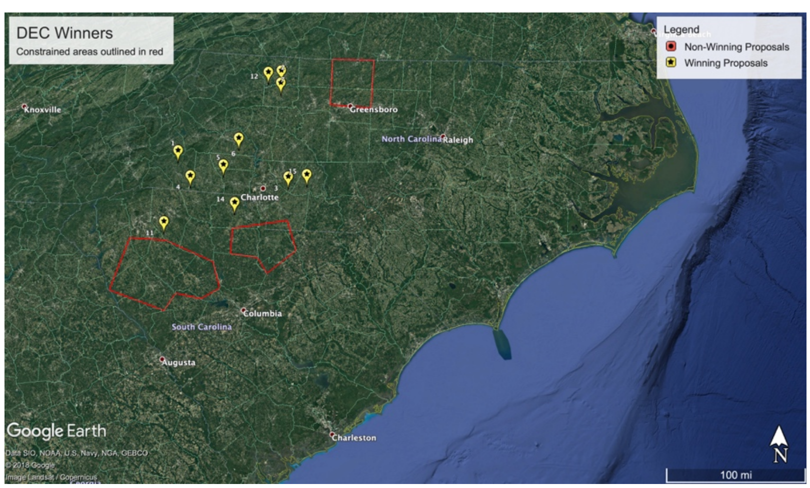


Figure 34



3. Distribution Guidance Provided to Bidders

MPs were advised that projects smaller than 20 MW would be evaluated as requiring distribution level service. Locational guidance was provided for projects that could interconnect at distribution level via materials posted on the IA Website or linked from the Website, as well as during the May 10, 2018 webinar. Specifically, a document entitled "Method of Service Guidelines" was identified by Duke and a link to the materials was included on the IA Website.

One of the two DEP winners is a 7.02 MW project that will interconnect at distribution level. The maps shown in Figure 35 and 36 show this project's location in a constrained area. The project was in the final Competitive Tier because it is well priced and a "late stage" project, meaning the MP accepted responsibility for system upgrade costs in the Proposal and only minor additional costs were imputed to the Proposal.

Figure 35

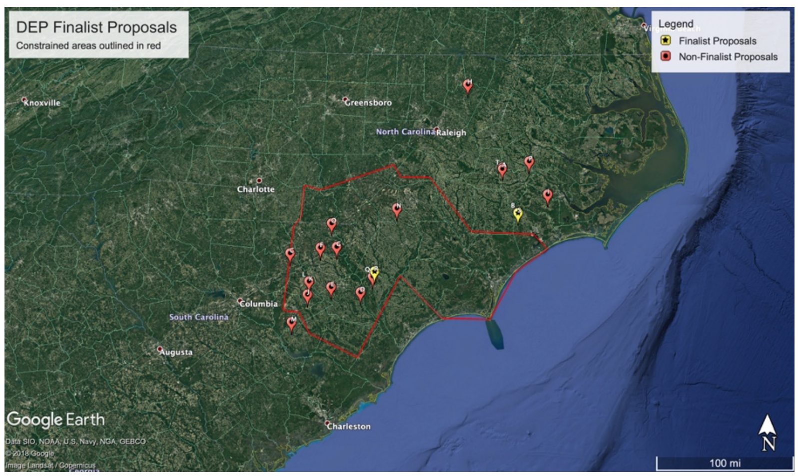
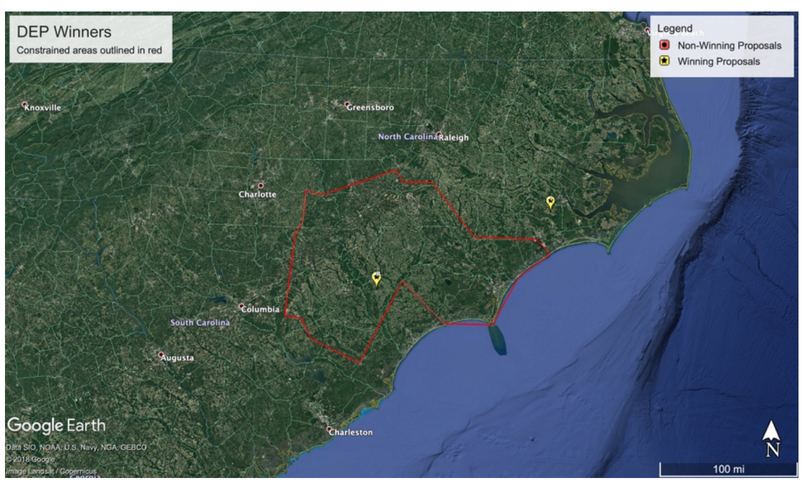


Figure 36



B. FLOW CHART OF STEP 2

In response to a request from the Commission Public Staff, the IA produced a flow chart showing the iterative approach to this cost determination was formulated. This flow chart was provided on the IA Website on September 19, 2018, and is included as Appendix C.

The flow chart was shared and discussed during face to face meetings with the subject matter experts on the T&D Team. As the team name suggests, Duke personnel with subject matter expertise in the areas of either transmission or distribution were assigned to the team. During the Step 2 evaluations, Proposals were separated depending on whether the associated projects would interconnect at either transmission or distribution levels and were reviewed by personnel experienced in the respective areas. The flow chart was followed throughout the actual analysis of Proposals to ensure that all Proposals were evaluated using the same process and standards.

C. ANALYSIS REPORT FORMAT

As part of the practice of treating each Proposal in a fair and equitable manner, a standard document was used to record and present the analysis results for each Proposal. A draft standard document was presented to both T&D Teams for consideration and modification. A mock Proposal was selected, and the Distribution team completed an example analysis to test the applicability of using this standard format. This example was shared with the T&D Team which adopted a similar approach.

D. COMMUNICATION DOCUMENTATION

After the Proposal submission period closed on October 9, 2018, a “T&D EVAL” folder and confidential Message Board was opened on the DEC Silo of the IA Website for data sharing with the members of the T&D Evaluation team. This platform ensured that the exchange of files, and the file contents, had a time and date stamp, and that all Proposal data was shared securely. All members of the team shared access to these files, and this process continued until the ranking of the Competitive Tier became final.

At the same time CPRE Proposals were being evaluated, the day to day operation of Duke transmission continued. Some Duke Account Managers had dual responsibilities in addressing non-CPRE requests for transmission service and being on the T&D Evaluation team. To avoid even the appearance of CPRE ranking information being released, the IA Website provided restricted access to separate folders, thereby isolating evaluation information access on a “need to know basis.” This approach prevented Duke Account Managers from viewing ranking information of Proposals, while the T&D Evaluation team, via a confidential file system, received the information needed to complete evaluations. These files are preserved on the IA Website for future review and confirmation.

Beginning on October 9, 2018, all voice or email messages between the IA evaluation team members and the T&D team were documented in a communication log with daily postings to the confidential evaluation files on the IA Website. Communication records were organized by week and posted to the “T&D Communication Log” folder on the Evaluation page of the IA Website.

All direct communication from members of the T&D Evaluation team to MPs concerning CPRE topics was prohibited. Instead, T&D Team members were instructed to provide questions to the IA, who in turn posted them on the confidential Message Board of the Website. This ensured complete documentation of all exchanges. There were no observed instances of MPs inappropriately approaching T&D Evaluation team members.

E. LATE STAGE PROJECTS

Late Stage projects were recognized in Tranche 1 as a special class of Proposals. To qualify for late stage status, a project was required to have an executed state jurisdictional Facility Study agreement as of the date of Proposal submission. A project that obtained Late Stage status retained its original queue position and original network upgrade costs, if any, even if it was not selected as a winning project. Late Stage status was an advantage for a project with little to no network upgrade costs identified in their existing System Impact Study. For a project already assigned significant network upgrade costs, foregoing Late Stage status allowed for sharing of costs in the CPRE pooling process. The advantage to Late Stage status was that a project retained its original queue position, even if it was not selected as a winning project.

Considerable discussions and interactions by the IA and Account Managers, Duke attorneys, and T&D Team members was necessary to make determinations as to Late Stage eligibility. Numerous questions and confirmations required MP's responses on the Message Board because of confusion about some projects. This process started in mid-October and was not competed until mid-December.

F. INTERCONNECTION VERIFICATION AND VALIDATION

The process of verifying and validating the information submitted by the MPs proved to be arduous due to confusion about queue identification numbering, whether projects were FERC-jurisdictional, and the precise POI of projects. The IA managed the confirmation process with assistance from Account Managers, T&D Team members, Duke attorneys, and the MPs. Because the identity and location of projects proposed into the CPRE program was to remain unknown to most Duke personnel, including those on the Duke Evaluation Team, information from Proposals was only provided when there was uncertainty about a Proposal, and then only to the Duke personnel with subject-matter expertise to assist the IA so the required separation protocols were maintained. Proposal verification started shortly after the close of bidding in October 2018, and continued into mid-January 2019. Those issues needing verification and validation are discussed below.

1. Facility Study Agreement Status

There were several instances where the facility study agreement for a project was executed by the developer, but the final acceptance was not executed by Duke. In other instances, the study was not complete, though the MP contended that it was. Each of these instances had to be resolved before a Proposal was included in the Step 2 evaluations.

2. Project Size

The CPRE maximum Proposal size for transmission connection was 80 MW; the distribution connection maximum was 20 MW. Project size was established in the interconnection request and could not be expanded, but could be reduced up to 10 percent. Confusion concerning project size was largely a result of lack of specificity on the Proposal form. Instead of using a uniform term, such as “Project Size,” the Proposal form required “capacity” size in different contexts. In cases where the Proposal form intended for MPs to submit project size, some bidders submitted nameplate MW, inverter capacity, or output MW to POI, resulting in inconsistent project capacity data. The appropriate MW capacity was established by the T&D Team through interaction with the MP on the Message Board. As a result of this process, this section of the Proposal form will be revised for Tranche 2 (“Lessons Learned”).

3. Transition from FERC to State

There were several examples where MPs desired to transition their FERC projects to State jurisdiction in order to participate in CPRE. This transition involved consultation with Duke attorneys for verification. Additionally, there were instances in which proper paperwork had not been filed to accomplish this transition, or the projects did not qualify for State jurisdiction. In each instance, the MP was informed of the final determination and did not challenge the result.

4. Queue History

The online Proposal form required identification of the queue number associated with the project. There were numerous instances where the MP used a queue number that was no longer valid, used the same queue number for multiple projects, or used a queue number that was invalid. In some instances, the MP presented the queue number provided by a Duke account manager, though it was determined the queue number was invalid. Similarly, there were instances of confusion as to the appropriate queue number to be used among differing Duke options and the FERC queue numbering system. The IA and the T&D Evaluation team resolved each issue prior to the start of the Step 2 evaluations, and prepared revised protocols for assigning queue numbers so the confusion will not reoccur.

5. Ownership Transition

It is common for some developers to initiate project development and then sell their project to another MP prior to completion of the project. Ownership transfers are required to be filed with Duke. Unfortunately, the documentation of ownership transition was not always filed or recorded properly. Each instance of inaccuracy in ownership documentation was investigated by the IA and the T&D Evaluation team and proper documentation was recorded prior to the start of the Step 2 evaluations.

6. Analysis Uncertainties

The T&D Evaluation team and the Account Managers identified several Proposals where the RFP data did not align with the existing information for the project. These included two Proposals which required clarification on their ability to successfully interconnect at the POI indicated on the Proposal Form, two Proposals where the intended POI was unclear, and several Proposals where the size presented on the Proposal Form differed from what was given at other points in the submission process.

7. Concluding Proposal Cures

The initial cure process was crucial to attaining the basic Proposal data needed for the ranking process. The majority of this work was completed by mid-November 2018, which allowed the Proposal ranking process to go forward. A few cures remained that were resolved in mid-December. These remaining issues did not delay the initial ranking analysis but did modify subsequent rankings.

As the Proposal cures were being resolved, it proved a challenge that Account Managers were not privy to the Proposal ranking data. Account Managers could only respond to specific questions from the T&D Evaluation team, and were also hampered in completing their daily tasks by their lack of CPRE Proposal knowledge. Both the T&D Evaluation team and the Account Managers were disadvantaged by this lack of shared knowledge.

G. STEP 2 PROCESS

1. DEC Transmission Proposals

At the conclusion of Step 1, Proposals were selected by the IA and sent to the T&D Team to begin Step 2 analysis starting on November 22, 2018. 18 Proposals totaling approximately 800 MW were included in the initial Step 2 analysis.

For each Proposal reviewed in Step 2, only information necessary to determine system impact cost was extracted from the Proposal submissions and provided to the T&D Team, and no Proposal pricing or calculated net benefit was provided. The information provided to the T&D Team is listed in Figure 37.

Figure 37

Name	Date modified	Type	Size
x_118-01_Facility_Description	11/21/2018 12:23 ...	Microsoft Word D...	12 KB
x_118-01_Project_Map	11/21/2018 3:26 PM	Adobe Acrobat D...	410 KB
x_118-01_Single_Line	11/21/2018 12:21 ...	Adobe Acrobat D...	460 KB
x_118-01_Single_Line_Drawing	11/21/2018 12:21 ...	Adobe Acrobat D...	460 KB
x_118-01_Site_Description	11/21/2018 12:22 ...	Adobe Acrobat D...	29 KB
x_118-01_Site_Plan	11/21/2018 3:26 PM	Adobe Acrobat D...	492 KB
x_118-01_Transmission_Project	11/21/2018 12:22 ...	Microsoft Word D...	22 KB

The T&D Team reviewed the contents of these files and identified issues for which additional information was needed from the MP. The T&D Team shared requests with the IA via a confidential Message Board on the IA Website and the IA, in turn, interacted with the MP to collect the information and pass it to the T&D Team. [15] This approach ensured that the T&D Team did not to have direct CPRE correspondence with the individual.

[15] Some requests were made via email and were then recorded in the communication log

2. DEP Transmission Proposals

Proposals for DEP were selected and sent to the T&D Team. Eleven (11) Proposals, totaling over 700 MW, were sent on November 29, 2018 with the same data identified in Figure 37. The IA used the same process as described above for collecting clarifying information from MPs when necessary.

3. Distribution Service Analysis

The two distribution Proposals in the Competitive Tier for DEC were delivered to the T&D team on November 29, 2018 along with the Figure 37 data.

H. THRESHOLD COST ESTIMATES

A review of the location of projects confirmed there were a number in the identified constrained areas where system upgrade costs would certainly be incurred. To avoid excess analysis, the IA prepared a table with an estimated maximum upgrade cost each Proposal could bear without exceeding avoided cost. If the analysis indicated that a long transmission line upgrade or a significant substation would be needed, the system upgrade costs were estimated and compared to the threshold values previously calculated by the IA. This quickly eliminated Proposals that would be above avoided cost, thereby streamlining the transmission analysis.

Threshold values of 600, 1,200 and 1,800 megawatts were established and calculated. Theses threshold values were established based on the 600 MW of CPRE generation that is to be added in Tranche 1.

I. MEGAWATT REDUCTIONS AVAILABLE

On the Proposal Form, MPs were asked if they would be willing to have their project sizes reduced by up to 10% if interconnection constraints were present, without changing the associated decrement price. This size reduction would not result in a change in the dollar per megawatt hour Proposal price. 31 MPs expressed their willingness to accept such a reduction if necessary. On December 12, 2018 a list of MPs willing to accept a reduction was sent to both the DEC and DEP segments of the T&D Team to be available should the IA determine it would be appropriate to reduce one or more Proposal in order to meet the Tranche 1 goals. The Tranche 1 evaluations were completed without the need to reduce the size of any Proposal.

J. BASE CASE FORMULATION

1. Overall Base Case Discussion

The T&D Team reviewed and established the base case after receiving the listing of ranked Proposal list on November 22, 2018. The process for confirming the base case required review of all projects in serial queue, elimination of duplicate projects, and elimination of untimely projects.

2. Review all Projects in Serial Queue

Initially included in each base case were all projects with a queue position established prior to October 9, 2018. Any project that bid into CPRE was removed from this initial base case, with the exception of Late Stage projects.

3. Eliminate Duplicate Projects

Some developers held queue positions for the same project with different configurations, such as different project sizing. Where there were multiple projects identified for a single location, only one could be built. Using engineering judgment, the IA and the T&D Team eliminated projects that could not proceed. At the NCUC's May 2019 technical session the IA suggested that between 50% and 80% of the projects in the queue would not be built. The IA believed that the base case should more accurately reflect the projects likely to be built.

4. Eliminate Untimely Projects

Tranche 1 required in service date, referred to as the Commercial Operation Date ("COD") of January 1, 2021. However, the IA and the Duke Evaluation Team recognized it would be inappropriate to eliminate an attractive Proposal if it could be in service shortly after the expected COD date. Accordingly, it was established that if a project could be completed by July 1, 2021, it would be considered as reaching a timely COD. Any project deemed not able to be in-service by this date could be excluded from further consideration. The construction timeline used for this determination was the normal completion times for the system components needed. The DEC T&D Team identified the transmission upgrades required for all Proposals analyzed. These upgrades were then evaluated and a determination was made as to whether the necessary upgrades could be completed by the required date.

The realistic COD cannot often be determined until after the network upgrade equipment requirements have been established. The causal connection between upgrades needed and the time required to construct will be further discussed in more depth below.

5. DEC Base Case

The DEC base case was formulated by excluding all combined cycle plants bid before October 9, 2018 that did not have an executed Interconnection Agreement. Subsequent studies of any plants excluded from the base case were adjusted such that those generators were not responsible for the costs associated with the upgrades caused by CPRE winners with later queue dates/positions. All other queued projects that were not duplicates from the same project were included in the DEC base cases.

Four transmission planning regions existed within DEC. Due to the size of DEC's generation queue, four base cases—corresponding to the four transmission planning regions—were created. Queued generation on the seams of each region were included in the respective base cases so as not to mask potential issues. The approach of using geographical groupings (based on the existing regional planning responsibilities) to create multiple base cases allowed for a systematic approach to assessing the impact of additional generation in different areas of the system.

6. DEP Base Case

The DEP CPRE Tranche 1 Base Case included all non-bidding and late stage requests, both FERC and State, with queue dates through October 9, 2018. There was one exception; a gas-fired combined-cycle plant which had a mutually exclusive alternative. Thus, combined cycle plants Q398 and Q399 were included in the base case and Q428 was excluded.

Due to the significant amount of solar generation in DEP, impacts from additional generation span the entire DEP region. Thus, all requests in DEP were modeled in a single DEP-wide base case.

7. Distribution Base Case

The Distribution Base Case differed from the others in that each project was evaluated based upon the loading of the line to which it was connecting and the substation loading into which the line connects.

K. COST ANALYSIS COMPLETED

The analysis approach evolved over time and was not finalized until mid-January 2019. The teams and the IA were in agreement as to the components of the required analysis.

TRANSMISSION

1. Standard Analysis Results Document

The format for the analysis report was proposed by the IA, tested, and was utilized successfully by the T&D Team as a way to document the analysis results for Proposals in the Competitive Tier. The following topics are included in each bid interconnection cost analysis:

- Proposal Information
- Study Purpose
- Study Conclusions
- Interconnection Configuration for the Proposed Proposal
- System Location of Proposed Proposal
- Analysis Structure and Assumptions
- Transmission or Distribution System Delivery Impacts
- Transmission or Distribution Facilities Estimate Including Upgrade Project Description
- Estimated Cost and Construction Time of Network Improvements

Individual analysis reports were completed for each Proposal in the Competitive Tier.

2. Analysis Results for Each Proposal

The T&D Evaluation team received the Proposal ranking in late November of 2018, 7 weeks after the Proposal closing date. At this point, the analysis of the individual Proposals began. The analysis results were produced in three steps: Analysis Content, Analysis Process and Results, and Track Progress and Status for All Proposals.

3. Analysis Content

The analysis content was driven by the bid analysis document. Each section of the analysis document helped to form the basis for the necessary network upgrades for each Proposal. To help the T&D Team understand and produce the required analysis and documentation of the analysis results, the IA met with the team approximately once a week. Each meeting had predetermined discussion topics that led to individual assignments, with results covered in subsequent meetings. These meetings began in February of 2018 and continued through mid-May 2019.

4. Analysis Process and Results

a. Evaluate in Ranked Order

The process for determining costs for each Proposal started with their ranked order. Proposals that were highest ranked had the lowest Proposal costs and were studied first; each Proposal was analyzed individually.

b. Apply Distribution Factor Test

If a Proposal location was within a previously identified constrained zone, a quick test was applied to determine whether the loading of constrained lines was likely to be too high as a result of connecting said project. Bidding into a constrained area did not disqualify a Proposal from being selected.

The Distribution factor ("DFAX") is a measure of the percentage of a facility's output that flows on a transmission element. Three percent (3%) is a commonly accepted threshold in the industry for assessing whether generators, loads, or transfers may materially impact the flow on a line or transformer.

Proposals in pre-identified constrained areas were screened against a 3% DFAX threshold on constrained facilities. Proposals that had > 3% DFAX on one or more constrained facilities in a pre-identified constrained area were excluded from further evaluation. The basis for this exclusion was unrelated to any impact on the cost of the Proposal (cost of upgrade may be spread across multiple projects) and was solely based on the inability to address constraints by July 1, 2021. While CPRE did not prohibit submission of Proposals in constrained areas, CPRE supporting documentation (i.e. locational guidance) indicated that Proposals in these constrained areas would have an increased likelihood of being subjected to system impact upgrades based on the level of activity in the queue. Proposals that did not have > 3% DFAX on one or more constrained facilities in a pre-identified constrained area were further evaluated, however projects whose necessary upgrades could not be completed by July 1, 2021 were removed from consideration.

c. Apply Standard System Planning Models

Both thermal overload and reactive capability analyses were completed using standard System Planning guidelines and models. The results of these analyses were reported in detail in the standard document for each Proposal. Four DEP Proposals completed bid analysis documents: two for distribution projects and two for transmission projects. Twelve bid analysis documents were completed for DEC Proposals: all were transmission projects.

d. Determine Network Upgrade Equipment Requirements

The analysis indicated whether there were any electrical deficiencies following the addition of the bid project. From there, the network upgrades needed to replace the deficiencies were determined. Standard unit cost tables were prepared based upon a project's completed history. The standard costs were then applied to each Proposal using the same costs for each construction unit for each Proposal.

e. Evaluate Impact on Commercial Operating Date of Upgrade Requirements.

After the extent of the upgrade requirements was known, the time taken to complete the field construction was predicted. It was important to understand this length of time when determining whether a Proposal could be operational by the time required in the RFP. The standard Proposal cost analysis document did not adequately recognize the importance of the construction timing requirement; the evaluation team suggests changing this document for Tranche 2.

f. Complete Reactive Capability Evaluation

The check performed by Duke Energy transmission planners was to confirm the plant design provided by the developer, or to advise the MP on the MW limitation.

Note that the DEC and DEP power factor requirements were published on OASIS in their respective Facility Interconnection Requirements documents. Developers were expected to design their plants to meet these requirements. The check performed by Duke Energy transmission planners was to confirm or correct the plant design provided by the developer.

The Evaluation Team also conducted a reactive capability evaluation. The following is an example of language used in one of the reports; "The maximum allowable size for a capacitor bank associated with a facility was 3.3 Mega-Volt Amperes Reactive ("MVAR"), which allowed the MP to compensate only for plant losses. With or without a 3.3 MVAR capacitor bank installed and in service, the requested MW output met the reactive" capability requirements set forth in DEC's FCR document, and the reactive power range was between 8.9 MVAR lagging and 5.6 MVAR leading.

g. Track Progress and Status for All Proposals

During the Proposal cost evaluation process, it was necessary to track status and progress for each individual Proposal. Individual records were maintained for DEC and for DEP. For all evaluation participants to have equal access to the same data, these files were maintained centrally and made available to authorized individuals on a regular basis.

DISTRIBUTION

As discussed below, there were three distribution Proposals that were bid into DEP: 67-01, 67-02, and 83-04. There was one such Proposal in DEC: 118-04. The process for considering distribution Proposals differs from the method that was used for transmission Proposals and will be covered separately below.

1. Analysis of Distribution Content

The distribution Proposals were restricted to a maximum of 20 MW and were required to connect at a distribution voltage. Because of their smaller size, distribution projects fit into more locations on the electric system. Thus, these projects were evaluated on the impact that they would make on a single circuit or on a single substation. Once the Proposal location was known, the analysis of electrical impact could begin. Distribution Proposals were also evaluated for their power flow impact on the transmission system. The same report document outline used for transmission was also used for distribution, but the smaller sizes of the distribution Proposals led to differences in analysis content and emphasis.

2. Distribution Analysis Process

The Distribution evaluation team had only four Proposals to evaluate. Coupled with the smaller amount of required analysis, this resulted in a significantly smaller workload. To assist in providing guidance for the Distribution team, the IA participated in team meetings approximately every other week. Discussion topics were prepared by the IA, which led to specific assignments and follow up items.

The overall analysis process, despite its smaller scope, was quite similar to that followed by the T&D Team. For example, the distribution analysis process was driven by the documentation requirements of the analysis template. The Distribution team was the first to thoroughly test the viability of the analysis document format.

L. VERIFICATION OF COST ANALYSIS RESULTS

One of the IA's critical responsibilities was ensuring that all MPs were treated justly and evenly. Additionally, the analysis process needed to align with industry standards and conform to normal evaluation processes used by Duke. The verification process began once all bid evaluation results were available. In mid-April 2019, the IA sent a request for in-depth verification data to both the Transmission and Distribution analysis teams, and the subsequent verifications occurred separately.

TRANSMISSION ANALYSIS VERIFICATION

As a part of the verification process, the Evaluation teams, through the IA, made informational requests of the MPs and used their responses to develop transmission network upgrade costs specific to each individual bidder. These requests were organized to investigate three main issues: Basis for Standard Costs, Testing of Load Flow Results, and Distribution Factor Validation.

1. Basis for Standard Costs

A review of the standard cost units applied to the network upgrade costs for the individual Proposals showed that "Modify Relay and Communication Equipment" was by far the most used cost. Thus, it was selected as the unit for more in-depth analysis.

DEP transmission Proposals did not have any upgrade cost adders for the two Proposals analyzed. Therefore, the focus was on DEC for this analysis. In the 12 winning DEC Proposals, the cost for communication equipment applied to the Proposals differed as follows:

- 4 Proposals connecting at 100 kV had costs of $225 K
- 1 Proposal connecting at 44 kV had a cost of $192 K
- 6 Proposals connecting at 100 kV had costs of $450 K

A request was made of the T&D Team to provide an explanation of these differences. Their response is provided below:

Only 2 of the 12 bids (83-06, 83-07) had scoped estimates since they had completed Facilities Study (and an executed IA). The other 10 bids relied on the standard cost template—for which there isn't really a "standard" cost when it comes to relay/communication modifications since those are project and station specific. The per station estimate in the standard cost template is high more often than not but does not exceed the per station estimate associated with 83-07. Furthermore, some of the bids are on radial lines and others are on network (or network capable) lines, which influences the number of stations to which project may need communication.

For the purpose of CPRE, a $225 K estimate is indicative of communication needs to a single station, whereas a $450 K estimate is indicative of communication needs to two stations. Any other estimates are indicative of a scoped estimate rather than an estimate based on the standard cost template.

As solar projects completed Facilities Studies, the relay/communication modification estimates likely lowered as a result of having more points of data. Nonetheless, any estimate was subject to project/station specific variance that could not be determined until detailed scoping and estimating has occurred, which did not happen until after a System Impact Study was performed. Recent Facilities Study Estimates are provided in Figure 38.

Figure 38

Queue #	Estimate
NC2017-03020	$73,569
NC2017-03020	$73,569
NC2017-03016	$52,728
NC2017-03016	$52,728
NC2017-03009	$57,380
NC2017-03009	$72,702
NC2017-02981	$25,742
NC2017-02981	$25,742
NC2017-02980	$38,924
NC2017-02980	$38,924
NC2016-02976	$117,450
3164	$96,689
3164	$126,241
3164	$110,437
8346	$141,620
10191	$117,321
10191	$100,120
10191	$83,274
42690	$95,508
42690	$95,855
42696-01	$423,844
42893-01	$76,520
42893-01	$42,435

The above explanation speaks to the variability of communication costs and showed that in many cases modifications were needed at multiple stations. The table provided illustrates actual data was variable but within the range of the standard cost for the "Modify Relay and Communication Equipment Standard".

2. Testing of Load Flow Results

A second area that was identified for more intensive investigation was the load flow results for two Proposals, one Proposal (143-05) that was selected as a winning bid and one Proposal (234-02) that was not selected as a winning bid. A request was made by the IA to provide the load flow results for Proposal 143-05. An excerpt of the provided load flow is shown in Figure 39.

Each line of the table contains information associated with an identified contingency; the green area includes Proposal 143-05, and the blue area contains the base case data. The "% Diff" column contains a calculation that provides a delta between the individual contingencies with and without the addition of the generation addition of Proposal 143-05. Note the little difference and thus little system impact as a result of the addition of this Proposal.

Figure 39

2021s CPRE 143-05						2021s CPRE Base					
New Rating	Rating	Pre-Cont	Post-Cont	Percent	Occurrences	Rating	Pre-Cont	Post-Cont	Percent	Occurrences	% Diff.
117	117	95.3	106.3	90.1	-	-	-	-	-	-	-
24.2	24.2	10.9	21.9	90.3	-	24.2	10.9	21.9	90.3	-	**0**
42.9	42.9	19.4	39.4	91.7	-	42.9	19.4	39.4	91.7	-	**0**
42.9	42.9	19.3	39.4	91.8	-	42.9	19.3	39.4	91.8	-	**0**
85	85	38.3	78.6	92.5	-	85	38.3	78.6	92.5	-	**0**
85	85	38.3	78.6	92.5	-	85	38.3	78.6	92.5	-	**0**
84	84	39.1	78.6	93.6	-	84	39.1	78.6	93.6	-	**0**
84	84	39.1	78.6	93.6	-	84	39.1	78.6	93.6	-	**0**
22.9	22.9	10.4	21.9	95.8	-	22.9	10.4	21.9	95.8	-	**0**
42.1	42.1	23.6	40.6	96.4	-	42.1	23.6	40.6	96.4	-	**0**
183	183	70.9	167.1	91.3	-	183	70.9	167.1	91.4	-	**0.1**
129	129	74.4	119.8	92.1	-	129	74.5	120	92.3	-	**0.2**
41.6	41.6	25.9	39.6	95.1	-	41.6	25.9	39.6	95.3	-	**0.2**
41.9	41.9	28.8	41.8	99.7	-	41.9	28.8	41.8	99.9	-	**0.2**
292	292	154.2	266.7	90.4	-	292	155	268.1	90.9	-	**0.5**
292	292	154.2	266.7	90.4	-	292	155	268.1	90.9	-	**0.5**
85	85	38.3	78.2	92	-	85	38.3	78.6	92.5	-	**0.5**
84	84	39.1	78.2	93.1	-	84	39.1	78.6	93.6	-	**0.5**

The losing Proposal, 234-02, was also examined for analysis accuracy. A report produced by the T&D Team shows the comment below for Proposal 234-02:

> *The tap line that 234-02 (83-10) and 336-03 are proposed on cannot accommodate both projects. If both projects are built, the project deemed to have the later queue position or to be less favorable will have to upgrade nearly 5 miles of 100 kV with an assumed cost on the order of $7.5 MM. Either project is also subject to constraints that have been identified on the DUK/SCEG interface that would require an Affected System Study with SCEG to determine potential adverse impacts on a neighboring system. The upgrades on the DUK side of the DUK/SCEG interface cannot be completed by 7/21.*

The requested load flow results for this Proposal, which are included below, illustrate the overload condition.

Figure 40

Monitored Element		Contingency	Limit	FlowInit	
306001 3CLARK H 115 308584 3BIGCOWHEADP 115 1		CLARKHILL-JST_MCCRMCK	119	217.5	Clark Hill 115 kV
309800 3MCCORMICKPV 115 339150 3JST-SC 115 1		CLARKHILL-CH_BGCWHD	119	217.5	Clark Hill 115 kV
306242 BUSH RIV 100 308226 NEWBERRYPV(A 100 1		CLINTONB_ANGSB	65	106.7	Champion 100 kV
306242 BUSH RIV 100 308579 TRINITYPV 100 1		CHAMPIONWH-BR_NWBRRY(D)	146	234.8	Champion 100 kV
306232 3BUSH R 115 307892 3NWBYC6 115 1		NEWBERRYWA	79	123.5	Newberry 115 kV

The results shown on line 5 at the bottom of the chart indicate that the Newberry – Bush River 115 kV line would be overloaded following the addition of this Proposal.

3. Distribution Factor Validation

The previous section discussed the application of the distribution factor, specifically how any distribution factor over 3% was an industry accepted indicator of significant contribution. Continuing with the analysis of failed Proposal 234-02, the IA requested distribution factor calculation results for the Newberry - Bush River 115 kV line. The chart below shows the distribution factor calculation results for each of the five lines shown in the table above.

M. STEP 2 PROCESS CONCLUSIONS

Based upon the entire body of work that was required to complete the system upgrade cost analysis for both transmission and distribution Proposals, the following conclusions are offered:

- The analysis process was the same for all bidders, being evenly and fairly applied to all Proposal s
- The T&D Team successfully adopted the standard Proposal cost analysis report format suggested by the IA. Modifications were identified by the team and were incorporated into the final document. These modifications were made to tailor the format to Duke requirements and standard practices.
- All T&D Team members worked well and focused on the tasks required to produce Proposal cost analysis results in a timely manner. Sufficient resources were available to complete the required tasks.
- The IA felt that communication with both teams and with the Account Managers was open and honest with a joint dedication to achieving quality and timely results.
- The verification tests proposed by the IA demonstrated a firm foundation for accurate cost analysis.
- CPRE tranche 1 was an excellent learning experience. Participants were open to suggested modifications in approach and were willing to attempt alternative solutions. The resulting analysis process will serve as a solid foundation going forward.

XII. SUBJECT MATTER AREAS

A. LEGAL TEAM REVIEW

The IA's legal team performed several tasks for Tranche 1 of the CPRE program. Prior to Proposal submission, the legal team prepared a Site Control Acknowledgement Affidavit. Following the Proposal closure date, the Legal Team reviewed the following documents for completeness: Site Deed, Site Lease, Site Control Acknowledgement, Title Insurance Copy, Title Insurance, Title Insurance Report, Boundary Survey, Description of the Site, Easements, Environmental Students, Facility Descriptions, Facility Permits, Other Permits, the Project Map, Project Map with Landmarks, and the Sitemap.

A compilation of this review was organized and submitted to the IA. Based on the Legal Team's review of the documents, the Proposals were scored by category as follows: permitting will be complete at the commercial operations date, project site control for the full term, and site control to the point of the interconnectivity. The Legal Team reviewed the above documents again for accuracy and to determine how they scored. A large portion of the Legal Team's time during the scoring process was spent reviewing easements for the transmission path and looking at leases and deeds to verify control coincided with the duration of the project.

B. FINANCIAL TEAM REVIEW

The Financial review conducted for CPRE Tranche 1 evaluated the credit-worthiness factors identified in the RFP (see Appendix F, item 6 – "Credit Worthiness"). The purpose of the financial review, as stated in the RFP, was to determine the "financial assurances to meet schedule and milestones in PPA." The credit worthiness of a Proposal was assigned five percent of the Proposal score, equal to 50 points of the total maximum score of 1000 points.

The financial review compiled information from the Proposal including information regarding ownership, plans for Proposal and performance security, and credit ratings. The Financial Review was conducted on all Proposals that advanced to the Step 2 evaluation. Given that Proposal security was required for all third-party Proposals that were advanced to the Step 2 evaluation, Duke's credit requirements and potential damages were secured by the Proposal security:

> *Proposal Security Amount represents a fair and reasonable pre-estimation of the damages due to Duke Energy…" and "represents a reasonable estimate of Duke Energy's losses in the event of (i) Bidder's withdrawal of the Bid following its selection for further evaluation in the Step 2 Evaluation Process, or (ii) Bidder's failure to execute the Agreement with Duke Energy for the Bid if selected as a winning Proposal or failure to provide Performance Assurance as required under the Agreement.*

The Financial Review assigned points based on the method of Proposal security selected by each MP advanced to the Step 2 evaluation. Credit-worthy MPs were assigned the maximum score (50 points). Non-credit worthy MPs were evaluated based on the various forms of Proposal security (cash, Letter of Credit, or Surety Bond) submitted to ameliorate credit risk. A non-credit worthy MP who posted cash for the Proposal security was assigned 50 points. A non-credit worthy MP who posted a Letter of Credit or a Surety Bond for Proposal security was assigned 45 points. Bidders who dropped out of Tranche 1 for failure to post Proposal security or for other reasons were not evaluated.

C. PROJECT SUFFICIENCY TEAM REVIEW

The IA Project Sufficiency Team was responsible for performing a detailed technical evaluation of each Proposal. The technical evaluation included a complete review of the project design and equipment specifications as well as a review of the experience of the MP's Project Team. This due diligence review was completed to confirm that any project the IA recommended for a PPA was technically capable of providing the service proposed.

To begin the evaluation, the PST reviewed each submitted Proposal form and identified the "pre-coded" data fields in the on-line Proposal form needed for evaluation of the project. The IA created an Evaluation File system, which was then used to develop a file repository for the PST evaluation of individual Proposals. The "Custom Reports" tool on the IA website was utilized to draw relevant data from each submitted Proposal.

The PST developed five custom reports:

1. Generating Facility (technical description of the site)
2. Solar Design (design and equipment specifications)
3. Storage Design (design and technical specification)
4. Project Status Summary
5. Proposal Summary

The PST also reviewed documents uploaded to the CPRE website by MPs, which included:

- Description of the project site
- Facility Description
- Inverter Warranty
- Operations (project costs)
- Project Map
- PV Ongoing Maintenance
- Single Line Drawing
- Site Map
- Site Plan
- Solar Information
- Specification Sheet (solar panels)
- Storage Spec Sheet
- Storage Experience
- Renewable Facilities Experience

In its initial examination, the PST reviewed each Proposal and its associated uploaded documents to determine whether the response was "complete and conforming," that is whether it provided all of the required information and met the RFP criteria. The PST found a number of deficiencies or questions about the project design. For example, some of the MPs entered the total installed DC rating in MW DC instead of kW DC. In some instances, data entries were left blank or the information that was entered required clarification. In each case where deficiencies or questions were noted, the PST posted messages to the MP's confidential Message Board providing the MP the opportunity to cure or clarify the information provided. Ultimately, all of the submitted Proposals were corrected and deemed conforming. No Proposals were rejected in the initial review and no Proposals were withdrawn by an MP.

Following the preliminary ranking of complete and conforming Proposals, the PST proceeded through its evaluation in the Initial Tier Ranking order. All Proposals were reviewed for the sufficiency of the project, with projects receiving a full technical review as they were included in the Competitive Tier. This approach permitted the best-ranked Proposals to proceed to the Step 2 review without delay, and those drawn from the Competitive Tier Reserve were reviewed sequentially.

The PST completed the relevant sections or subsections of the Sample Scoring Sheet for each of the Proposals. The PST addressed the following subsections: Experience of the Project Team, Equipment to be used, Required Control Equipment, and Quality of Project Design. A complete breakdown of scoring requirements can be found in Appendix F of the RFP.

XIII. ACQUISITION PROCESS AUDIT

A. OVERVIEW

The IA conducted an audit of the CPRE Tranche 1 Asset Acquisition program. The Asset Acquisition program was designed for Duke to acquire Renewable Energy Resources consistent with the CPRE requirements to be developed through either a Renewable Resource Asset Transfer plus Engineering Procurement and Construction ("EPC") agreement, a Build Own Transfer ("BOT") agreement, or a Renewable Resource Asset Transfer Agreement. The DEP/DEC team could submit Proposals [16] chosen to be sponsored from the Offers presented on the AA Silo of the IA Website, and projects to be developed directly by Duke. Proposals for direct development by Duke were required to be submitted no later than October 8, 2018, which was at least one day before other MPs. The deadline for developers to submit Asset Acquisition Proposals was October 9, 2018. Asset Acquisition Proposal were evaluated by the DEP/DEC team and if selected, were converted by the DEP/DEC Team into a $/MWH price that was evaluated by the IA in the same exact same manner as other PPA proposals. The DEP/DEC team was required to submit its sponsored Asset Acquisition proposal via the IA Website on November 16, 2018. The time between October 9, 2018, and November 16, 2018 was used by the DEP/DEC team to evaluate the Asset Acquisition Proposals.

Proposals for sponsorship by the DEP/DEC team were identified to the IA and the Proposal data was directly transferred to either DEC or DEP, as appropriate. This transfer avoided errors in the transfer of data and ensured that each sponsored project was evaluated with data presented to the DEP/DEC team by the developer.

The DEP/DEC team selected five projects Duke would agree to acquire and sponsor in CPRE. Once submitted on the IA Website by the DEP/DEC team, the sponsored projects were evaluated using the same standards as all other Proposals. The IA's initial ranking of Proposals was adjusted once the sponsored projects were received and evaluated.

The AA Audit focused on the review of the design and execution of the Duke AA program. The review of the Duke Evaluation process included meetings with the Duke DEP/DEC Team to confirm the data collected on the IA Website was consistent with the information necessary for the DEP/DEC team to review offers from developers during the development of the on-line Proposal Form and after offers from developers. The criteria used by the IA in the review of the Asset Acquisition Offers included confirming the Offer was in compliance with CPRE, whether the Offer would meet the Required Commercial

[16] To avoid confusion, "Proposal" is used for projects submitted in DEC or DEP. "Offer" is used for projects submitted for acquisition consideration.

Operating Date ("RCOD"), and whether the project was capable of operation within the CPRE requirements

MPs were permitted to propose a project for a PPA and also to be acquired by Duke. Part of the IA's review included comparison of the five Duke-sponsored AA Proposals that were sponsored with the PPA submissions by MPs of the same projects. In every case when a project was proposed for a PPA by a developer and also submitted as a sponsored project for acquisition, the Duke-sponsored Proposal was found to provide greater Net Benefit.

B. AUDIT OBJECTIVE

As a requirement of the Duke CPRE Tranche 1, the IA performed an audit of the Duke Asset Acquisition Offer evaluation, assessment, and selection process. This audit was to determine whether the offers submitted to the Duke DEP/DEC team were complete and compliant with the CPRE requirements for eligibility. Further, IA reviewed the projects selected for acquisition to determine whether the DEP/DEC team materially modified the projects before submitting them into the CPRE program.

MPs could elect to submit Proposals for a PPA to DEC or DEP, as an Asset Acquisition Offer conforming to one or more of the AA structures, or the MP could offer a project as both seeking a PPA and an Asset Acquisition Offer. Twenty AA Offers were submitted in the CPRE Tranche 1. Figure 41 summarizes the submissions.

Figure 41

	Asset Transfer with EPC	Build Own Transfer ("BOT")	Asset Transfer
Proposed	9	7	4
Sponsored (DEC)	3	0	0
Sponsored (DEP)	0	2	0

C. THE AUDIT

Subsequent to the submission of projects being sponsored for acquisition, the IA Audit team met with members of the DEP/DEC team for the purpose of reviewing the selection process. The review included review of the criteria for selection, identification of the ranking of each offer, why certain projects were not selected for acquisition, identification of any design change requested by the DEP/DEC team, and final contracts with each project selected for acquisition.

Duke provided the following information to the IA:

- Evaluation Methodology Overview: described the process implemented to review, evaluate and rank all AA Offers received. This included non-economic (technical) and economic evaluation criteria.
- Assessment process summary: rank ordered the 20 AA Offers.
- Selection process for each of the five sponsored AA Offers.
- A summary of Capacity Cost in normalized $/MW AC, Total Energy in MWh, and COD for the 5 sponsored projects.

The IA also reviewed the non-economic and economic evaluation criteria used in evaluation and scoring for each of the 20 AA Offers and found the criteria to be appropriate.

1. DEP/DEC Team Evaluation Methodology Overview

The DEP/DEC team developed an evaluation process to review, evaluate, and rank the AA Offers. This process included both a technical (non-economic) evaluation and an economic evaluation with detailed criteria and a point system to score each Offer. The technical evaluation was used to assess the Offers to determine if the Offer met development, technical, and quality standards. An economic evaluation was conducted only if the Offer passed the technical evaluation.

The criteria for the technical (non-economic) evaluation included:

a. Status of site control
b. Quality of system design (optimal DC/AC ratio, NCF, constructability)
c. Design standards meet DEC/DEP requirements
d. Zoning and entitlements/community outreach
e. Site investigation/environmental studies
f. Project schedule
g. MP experience
h. Status of interconnections

Each of the non-economic criteria had a ten-point scoring system. All scores were multiplied by five, with a total of 400 points available. A minimum score of 200 points was required for the non-economic evaluation. If the resulting score was less than 200 points, the Offer was eliminated, and an economic evaluation of the Offer was not conducted. If the Offer's score was greater than 200 points, a detailed economic evaluation was conducted.

The DEP/DEC team conducted financial modeling using inputs such as project capex, project production estimates, and project operations and maintenance cost. The economic evaluation was assigned a maximum point score of 600 points and the Offers were ranked based on the combined non-economic and economic score of the Offer. The offers for acquisition by BOT or EPC were compared side by side. The DEP/DEC team considered project risk, including but not limited to environmental risk, development risk, construction risk, cost and schedule risk. Eight Proposals did not pass the non-economic evaluation and were eliminated.

The final Offer selection was based on the combined economic and non-economic evaluations. The Duke AA Evaluation Methodology was comprehensive and balanced. The CPRE guidelines included examples of technical scoring criteria and the DEP/DEC team criteria were consistent with the CPRE program guidelines. The non-economic criteria for the technical evaluation, including the weighting and the scoring, were reasonable and appropriate to meet Duke's specification, standards, and quality for a Company-owned asset. The scoring and weighting were similar to the scoring and weighting used by the IA in evaluating and ranking the PPA Proposals; in both cases the non-economic scoring had a 400-point maximum score and the economic score had a 600-point maximum. The AA evaluation criteria were applied consistently to each of the 20 AA Offers.

2. Assessment Process

The DEP/DEC team created individual Excel spreadsheets to document the evaluation and scoring of each Offer. DEC received a total of six Offers and DEP received 14. From the 20 individual spreadsheets the IA prepared a summary Excel spreadsheet of the 20 AA Offers in rank order that included the Offer scoring, the disposition of the Offer, and highlights (notable deviant scores) of the reasons for the disposition of the Offer. The Offers were ranked and scored as follows:

Exhibit 2

Figure 42

DEC					
Masked Offer #	Non-Economic	Economic	Total	Observations:	Disposition
111-11	210	420	630	Secured proper zoning and permits (2/10) - Status of Interconnection (0/10) - Economic (7/10)	project was sponsored
111-12	265	360	625	Economic Criteria (6/10)	project was sponsored
111-13	260	300	560	Status of interconnection (0/10) - Economic Criteria (5/10)	project was sponsored
111-14	250	120	370	Economic Criteria (2/10)	project was not selected to be sponsored
111-15	190	N/A	190	Site Investigation - Interconnection - Economic - (0/10) -	project did not pass non-economic evaluation
111-16	135	N/A	135	Site Control - Quality of system - Zoning Permits - Site Investigation - Interconnection Study - Economic Criteria - (0/10) -	project did not pass non-economic evaluation

Figure 43

DEP					
Masked Offer #	Non-Economic	Economic	Total	Observations:	Disposition
11-1	200	480	680	Zoning permit - Site Investigation - Interconnection status -(0/10)- Economic Criteria (8/20)	project was sponsored
11-2	295	360	655	Interconnection Status (0/10) - Economic Criteria (6/10)	project was sponsored
11-3	250	300	550	Interconnection Status (0/10) - Economic Criteria (5/10)	project was not selected to be sponsored
11-4	300	240	540	Project Schedule (0/10) - Economic Criteria (4/10)	project was not selected to be sponsored
11-5	325	180	505	Economic Criteria (3/10)	project was not selected to be sponsored
11-6	275	180	455	Project Schedule (0/10) - Economic Criteria (3/10)	project was not selected to be sponsored
11-7	210	240	450	Interconnection Status (0/10) - Economic Criteria (4/10)	project was not selected to be sponsored
11-8	225	180	405	Zoning permit - Site Investigation - Interconnection Status - (0/10) - Economic Criteria (3/10)	project was not selected to be sponsored
11-9	190	N/A	190	Site Control - Site Investigation - Project schedule (0/10)	project did not pass non-economic evaluation
11-10	175	N/A	175	Site Control - Site Investigation - Interconnection Status - (0/10)	project did not pass non-economic evaluation
11-11	175	N/A	175	Zoning Permit - Interconnection Status - (0/10) - Site Investigation (2/10) - Quality of system (3/10)	project did not pass non-economic evaluation
11-12	175	N/A	175	Zoning Permit - Interconnection Status - (0/10) - Site Investigation (2/10) - Quality of system (3/10)	project did not pass non-economic evaluation
11-13	125	N/A	125	Site Control - Quality of System - Zoning Permit - Site Investigation - Interconnection Studies - (0/10)	project did not pass non-economic evaluation
11-14	125	N/A	125	Site Control - Quality of System - Zoning Permit - Interconnection Status - (0/10)-	project did not pass non-economic evaluation

Since the evaluation was completed in a step function process where projects were eliminated due to the non-economic factors and only the technically viable projects were advanced to the economic evaluation, there was no need to re-rank the projects. There was no single criterion that eliminated an Offer, but rather a number of criteria that varied for each Offer contributed to an Offer's elimination. Eight projects were eliminated because they did not pass the minimal 200-point score in the non-economic evaluation. Of those eight projects, project site control and zoning was a common factor for their elimination. Of the remaining 12 Offers, 7 were not selected to be sponsored primarily because the project economic evaluation resulted in less competitive pricing. A total of 5 projects were selected to be sponsored: 3 projects in DEC and 2 projects in DEP.

The DEP/DEC team indicated that the only design changes or modifications made from the initial Offers were inverter selections. All MPs included non-company approved inverters in their original interconnection application, and the five Duke-sponsored Proposal MPs were informed that the inverters would need to be updated. The IA conducted a review and comparison of the Duke-sponsored Offers and the corresponding MP PPA and affirmed that there were no apparent design changes or modifications from the initial Offers, except for 11-1.

In response to the IA's inquiry as to why the Self-Build team selected only five projects, the Self-Build team indicated that there was a total capital investment that was authorized for CPRE Tranche I participation (self-build proposal and sponsored asset acquisition Offers) and sponsoring more than the five would have increased the likelihood of exceeding the authorized capital. The authorized amount was not requested by or shared with the IA.

3. Selection Process

Figure 44 presents the five Duke-sponsored Proposals. [17]

Figure 44

Proposal #	Total Energy (MWh)	COD
DEC		
111-11	159,546	12/31/2020
111-12	129,670	12/31/2020
111-13	166,675	12/31/2020
DEP		
11-1	196,557	12/31/2020
11-2	205,041	12/31/2020

As stated above, each of the five Duke-sponsored Proposals had a corresponding and competing PPA Proposal from a Market Participant for the same facility. There was no requirement in the RFP for an MP to offer the same facility design in its PPA Proposal for a specific facility, nor was there a requirement

[17] Proposal numbers are "blinded."

that an MP offer a PPA Proposal corresponding to its AA Proposal to Duke. In this instance, there was a corresponding PPA Proposal for each Duke-sponsored Proposal.

With the exception of one of the five Duke-sponsored Proposals, which will be discussed later, the IA determined that each Duke-sponsored Proposal was essentially consistent in design and anticipated performance with the corresponding MP PPA Proposal for the same facility. This review was accomplished through several steps including:

- Review of the AA Silo on the CPRE website (submission documents, cure documents, correspondence, etc.);
- Review of the materials provided to the IA by Duke personnel in response to this Audit;
- Comparison of the Proposal Forms for each Duke-sponsored Proposal with the Proposal Form for its corresponding MP PPA Proposal; and
- Review and comparison of the annual energy, load profiles, capacity, and capacity factor of each Proposal.

In this analysis the IA compared the essential components of each of the five "pairs" of the Duke-sponsored and the corresponding PPA Proposals. The purpose of the analysis was to determine any differences between the Duke-sponsored Proposals and the corresponding MP PPA Proposals since each was derived from the same facility.

The IA reached four conclusions from the analysis of Duke-sponsored and MP PPA pairs. First, in four of the pairs, the Duke-sponsored Proposal had a significantly higher Net Benefit than its corresponding MP PPA Proposal. Given that the capacities, capacity factors, and energy profiles were virtually identical with each pair, the difference in Net Benefit was entirely explained by the lower prices offered in the Duke-sponsored Proposal.

Second, in the fifth pair, the capacity of the Duke-sponsored Proposal and the MP PPA Proposal was consistent. However, the Net Benefit of the Duke-sponsored AA Proposal was greater than the MP's PPA Proposal. The IA sought to understand why there was a larger pricing differential in this pair versus the other four pairs.

Third, the IA analysis of the fifth pair concluded that the energy and capacity benefits showed that the "raw" benefit (costs avoided by the Proposal) on a \$/MWh basis was virtually identical for both the Duke-sponsored Proposal and MP PPA Proposal. The total annual energy for the Duke-sponsored Proposal for this facility was 7% greater than the annual energy projected by the MP PPA for the same facility, thus providing an explanation of the greater pricing variance for the Duke-sponsored Proposal in this pair as compared to the pricing variance for the other four pairs in which the Duke-sponsored Proposal included the same quantity of energy as its corresponding MP PPA Proposal.

In summary, the energy profiles of the fifth pair were nearly identical resulting in nearly identical \$/MWh benefits for this pair regardless of the scale of the energy. The IA concluded that the higher quantity of energy in the Duke-sponsored Proposal reasonably explained the greater pricing differential in this pair as compared to the pricing differential in the other four pairs.

D. AUDIT CONTRACT REVIEW

The IA reviewed the status of contracts for each of the sponsored Proposals when the IA met with the DEP/DEC team and confirmed there were no binding commitments between the DEP/DEC team and the relevant developers. The DEP/DEC team confirmed that MPs were asked to submit a redline copy to the standard agreements provided in the RFP along within their AA Proposals. The DEP/DEC team confirmed that they had reviewed all redlined documents provided with Offers and would commence final contract negotiations when it was known if a sponsored Proposal was selected as a finalist.

The IA also reviewed the AA Silo of the Website for review of contract communications. This included communications in writing on the Message Board and communications contained in cure documents uploaded by the MPs. The written messages included the scheduling of, and action items from, several telephone conference calls between the parties. [18]

The IA Website clearly documented and preserved all such information exchanges and negotiations between Duke and MPs regarding such topics as:

- Commercial details including progress payments in the asset transfer contracts to establish the final negotiated $/kW price of each Proposal
- PVsyst [19] input/output forms
- Reference projects of similar or greater size than the proposed project
- Development and construction scope to be performed in-house and to be subcontracted by the MP
- Complete and detailed financial information on the MP and its financing partners
- The existence of a Fee-in-Lieu-of-Taxes ("FILOT") agreement in place with the authority having jurisdiction [20]
- An unredacted version of the lease agreement to allow Duke to confirm the structure of the lease

Based on this review, the IA concluded that communications between Duke and the MPs were well documented, unbiased, and consistent with Duke's evaluation and ranking of Proposals.

E. ACQUISITION AUDIT CONCLUSIONS

The Duke AA Evaluation Methodology was a comprehensive and balanced process. The Proposals submitted by the DEP/DEC team were compliant with the requirements of the CPRE program. The evaluation criteria were applied on a consistent basis to each of the 20 Asset Acquisition Offers submitted. The non-economic and economic criteria, as well as the weighting and the scoring, were reasonable and appropriate to meet Duke's specifications and standards for a Company-owned asset. Duke's scoring and weighting were similar to the scoring and weighting used by the IA in evaluating and ranking the PPA

[18] Duke offered to share meeting notes from the telephone conference calls if the IA requested them.
[19] PVsyst is a solar photovoltaic preliminary design tool for use by architects, engineers and researchers.
[20] Duke stated that such an agreement is integral to determining whether the project meets Duke's economic and project schedule requirements.

Proposals. In both cases the non-economic scoring had a 400-point maximum score and the economic score had a 600-point maximum. The five Proposals with the highest combined non-economic and economic scores were selected to be sponsored by Duke.

The DEP/DEC team provided the opportunity for comments on draft form agreements at the time MPs submitted projects for acquisition. The DEP/DEC team did not have non-negotiable pro-forma agreements for developers, as was done with the pro-forma PPA for the DEP and DEC solicitations. Similarly, there was no binding letter of intent or MOU that bound the MP to abide by the form agreement or hold their asset acquisition bid price. That shortcoming was highlighted when one MP withdrew the Offer behind a Duke-Sponsored Proposal on June 26, 2019: 12 days before the end of the contracting period. Because there was no binding commitment, the developer was not penalized for withdrawing the Offer, and the DEP/DEC team was without recourse to enforce the commitments received from the developer. As identified in the "Lessons Learned" section above, the IA and Duke will recommend improvements to the Asset Acquisition structure, such as a letter of intent or MOU between Duke and the developer of an Asset Acquisition project that will improve the certainty and clarity of the process.

XIV. FINALISTS

Twelve Proposals were selected as winners for DEC at the end of Step 2 on April 9, 2019. The projects ranged from seven MW to 80 MW for a total group of selected proposals totaling 515 MW. Two of those selected Proposals included storage. On July 8, 2019, one of the 12 winning Proposals for DEC withdrew. The identity of the MPs that withdrew are identified in Confidential Attachment 1.

After being selected as a finalist for DEC, one of the MPs indicated a desire to amend the PPA price bid due to changes in the cost of materials. The IA declined to permit the change. Subsequently the MP asserted the desire to withdraw claiming that Duke personnel affirmatively declared that the interconnection for the associated project would not be completed in time to meet the in-service date the MP identified in its Proposal. The claim was erroneous. The MP defaulted by failing to complete the PPA proffered by Duke. With both requests for the right to withdraw the MP requested release of the Proposal security. The IA declined to support the release of the Proposal security. At that time there were no longer any competitive and available Proposals in DEC to consider as a replacement. Therefore, the final result for DEC from Tranche 1 of CPRE is 464.5 MW of renewable capacity.

Three Proposals were quantified as potential winners in DEP at the end of Step 2. The RFP established that up to 80 MW would be selected, with the possibility of exceeding that amount by up to 5%. The selection of all three finalist Proposals would result in a total of 167 MW being selected, which was unacceptable. For this reason the IA recommended Duke accept two Proposals in DEP for a total of 87 MW. The best ranked Proposal was from a small project, which necessitated selecting the next best ranked Proposal in order to get close to the Tranche 1 goal for DEP. On June 26, 2019, Duke Energy informed the IA that the ultility self-developed Proposal (which was a conversion of an Asset Acquisition Proposal) that was selected as a winning Proposal in DEP was withdrawing along with another utility self-developed conversion of an Asset Acquisition Proposal. The reason for the withdrawal of the DEP Asset Acquisition Proposal is described in the report above, that is the developer and Duke were unable to agree on a final price for the project. The IA reviewed the ranking of DEP projects and immediately contacted the parties representing the next most competitive and available Proposal. They were able to proceed to contracting and executed a PPA within the timeline required by the RFP. Therefore, the final result for DEP from Tranche 1 of CPRE is 85.72 MW of renewable capacity.

XV. CONCLUSIONS

The Tranche 1 experience identified opportunities for improvement for Tranche 2. While an improved process should produce an even more robust response from the marketplace, none of the issues identified in this report should be understood to be a fatal flaw in the initial program design. Indeed, the IA believes Tranche 1 was successful in establishing a viable process for competitive procurement of resources.

The IA is hopeful that the Commission, Duke, and stakeholders will embrace the recommended changes presented as Lessons Learned, and further implementation of improvements before the Tranche 2 Proposal date.

Exhibit 2

APPENDIX A

SAMPLE PRICE SCORING SHEET

SCORING SHEET

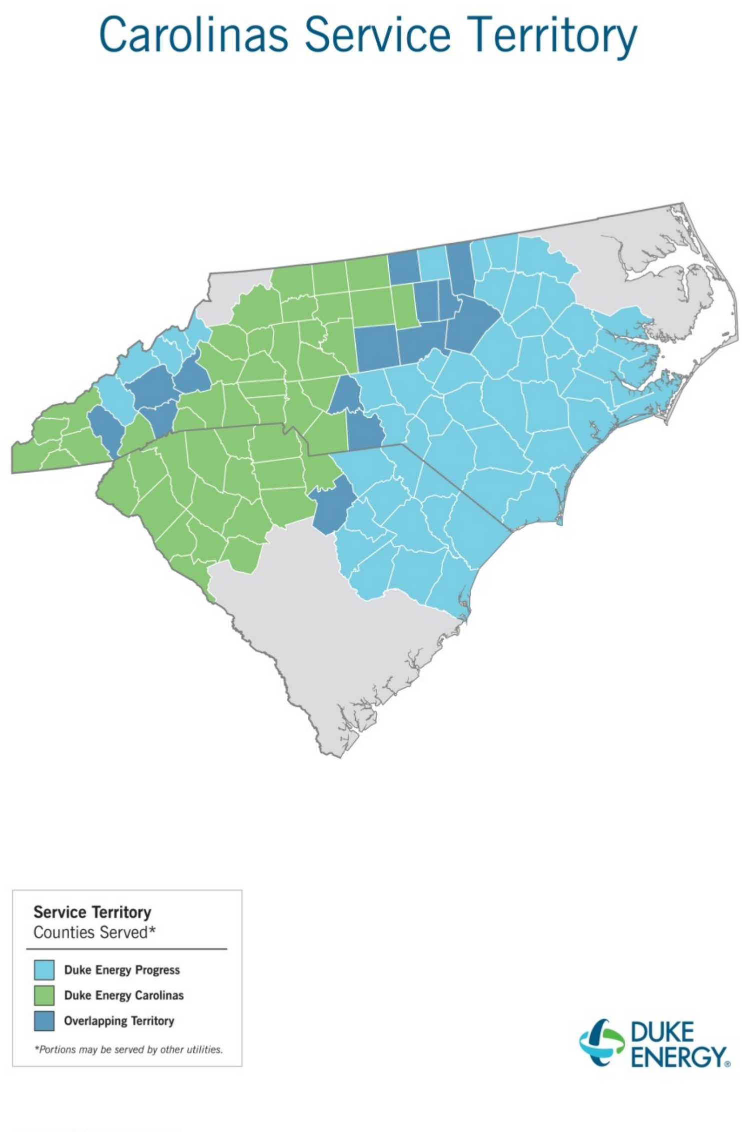
Bid Scoring Categories	Bid Score	% of Bid Score	Description	Individual Categories	Maximum Scoring	Section Score
1. Price Score		60%	Includes fixed and variable bid costs	The price score will be calculated on the basis of the bid's projected total cost per MWH	600	
2. Project Development Criteria		15%	Respondent must show sufficient evidence of ability to provide services included in proposal for the contract term Evidence of operational capability to provide proposed services	-Demonstrate that permitting will be complete to meet COD -Experience of project team -Project Site control for full term -Site control to POI for full term	30 30 50 50	
3a. Facility Project Characteristics 3b. Transmission Project Characteristics		15%	Evidence of equipment designed to meet specifications Interconnection Transmission Rights	-Equipment to be used -Required control equipment (TBD) -Quality of project design -Submitted completed interconnected request and obtained a queue number	30 30 30 50	
4. Project Characteristics		4.5%	Value of Project Characteristics	Demonstrates ability to meet performance guarantee and liquidated damages pursuant to the PPA	45	
5. Historically Underutilized Businesses		.5%	Ownership by Minorities (to be defined)	Ascertain that at least 51% of venture is owned by eligible minority	5	
6. Credit Worthiness		5%	Financial assurances to meet schedule and milestones in PPA	-Confirms meeting all Duke credit requirements -Project financing confirmed -Bond rating -Net tangible worth -Liquidity	50 /or/ 20 10 10 10	
Total Score	1,000	100%			1,000	

Exhibit 2

APPENDIX B
LOCATIONAL GUIDANCE

Overview

Duke Energy offers energy services to approximately 7.4 million customers in the Carolinas, Florida, Ohio, Kentucky and Indiana. The Carolinas area is comprised of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). The DEC service territory is approximately 24,000 square miles and serves 2.5 million residential, commercial and industrial customers. Primary transmission voltages in DEC are 500kV, 230kV, 161kV, 100kV, 66kV, and 44kV. The DEP service territory is approximately 32,000 square miles and serves 1.5 million residential, commercial and industrial customers. Primary transmission voltages in DEP are 500kV, 230kV, and 115kV.



Planning the Transmission System

The analysis performed by Duke Energy in planning the transmission system is based on good utility practice and NERC Reliability Standards. The analysis is performed to ensure reliable service can be provided to all customers considering that outage events (lightning, car accidents, equipment failure, faults, etc.) that cause transmission and generation elements to be removed from service can and do occur. Outage events can impact the voltage levels and the power flows on the transmission system in ways that would stress the system beyond its capabilities if the system were not properly planned, resulting in customer outages or poor power quality. Addition of new transmission and distribution connected load and generation requires ongoing analysis to ensure continued operation within limits. When analysis indicates limits will be exceeded, modifications or upgrades to the system must be identified to ensure continued reliable operation. The decisions to upgrade or modify system elements are made by applying reliability standards on an equivalent basis to all interconnection requests, and selected solutions to system issues are identified to minimize costs to the total body of Duke Energy customers.

When a new generation project requests transmission interconnection, Duke Energy is required to assess the impact of the new generation on the electric system. The assessment identifies locations where modification or upgrade of the transmission system will be necessary to maintain reliable service to all interconnected electricity customers, including consideration of possible outage events. The assessment includes the impacts of distribution-interconnected generation projects, which also affect transmission system loadings.

As a result of analyses performed to date, Duke Energy has identified areas where modification and upgrade of the system would be required if generator projects in the queue were to be interconnected. The areas where proposed projects have already indicated a need for transmission upgrades are identified on the constrained area maps. In other words, projects already under consideration, located in constrained areas, have resulted in demands exceeding the transmission grid capability and, if they are pursued to commercial operation, will require additional transmission capacity. Any new or additional transmission or distribution interconnection requests submitted in these constrained areas, after those currently in the queue for analysis, will possibly contribute to additional upgrade needs that may add project costs.

The need for transmission system upgrades is subject to the final disposition of the individual projects, i.e., whether or not they are pursued to commercial operation. Thus, the need for transmission system upgrades can be subject to change as additional projects are analyzed or individual projects decide not to continue with the interconnection process. Therefore, the identification of constrained areas should be considered a snapshot based on conditions known at the time. However, developers of potential projects in the identified constrained areas should be aware that there is a risk of additional transmission grid upgrades, which could result in additional costs and lead time requirements for the project. This would include distribution interconnected projects, which also impact transmission system loadings.

DEC Generator Interconnection Requirements - Overview

Transmission level projects participating in the DEC CPRE are likely to interconnect to either the 100 or 44 kV system. Unless a project is interconnecting directly to an existing 100 kV station, the project will interconnect via a tap to a single 100 or 44 kV transmission circuit. For 100 kV projects tapping a single circuit, this design will typically include a three-way gang operated air break switch in line with the main line and a breaker (or circuit switcher) on the tap line at the point of change in ownership. For 44 kV projects tapping a single circuit, this design will typically include a 4-pole bent in line with the main line, disconnect switches, and a breaker (or circuit switcher) on the tap line at the point of change in ownership. For both 100 kV and 44 kV projects, the design will include a transfer trip scheme for faults anywhere on the main or tap line.

Transmission level projects participating in the CPRE may be permitted to interconnect directly to an existing 230 kV station. Any 230 kV interconnections not directly into an existing station require the generation aggregated at a new station to exceed 120 MW.

For additional details, refer to the DEC Facility Connection Requirements located under Generator Interconnection Information at the DEC OASIS website[21].

Constrained Areas in DEC

For DEC, the constrained area map (Attachment 1) represents areas of the transmission system where there are either known transmission constraints that would be aggravated by increased generation or transmission constraints that are created by queued generation. These transmission constraints have been identified by either Transmission Planning or System Operations and have been confirmed through transmission studies of one or more generator interconnection requests. Transmission upgrades to mitigate the constraints already identified would exceed $10 million, and lead time is dependent upon the scope of work but would exceed 1 year, and possibly be as long as 3-4 years. Generator interconnection requests in areas not identified as constrained may also require transmission upgrades, but transmission studies are required in order to make this determination.

There are three constrained areas identified in DEC. In Guilford and Rockingham counties, off-peak conditions can drive post-contingency thermal loading issues on 100 kV lines that emanate from Dan River. Increased generation in these two counties will make the 100 kV lines in the Dan River area more susceptible to both off-peak and on-peak loading issues. The other two constrained areas shown are areas on DEC's system with the highest penetration of queued solar generation. The six county area near DEC's southern border including Newberry, Laurens, Greenwood, Abbeville and portions of Greenville and Anderson counties has over 1600 MW of queued solar generation. The other is a three county area

[21] https://www.oasis.oati.com/duk/index.html

located near the DEC/DEP border including Chester, Lancaster and Union (NC) counties that has over 600 MW of queued solar generation.

A DEC constrained infrastructure list is available that documents the individual transmission lines and substations that are in the constrained areas.

Additional transmission line mapping information can be found at the Energy Zones Mapping Tool website[22].

DEP Generator Interconnection Requirements - Overview

To connect to the DEP 230 or 115 kV transmission system, a generating plant should be at least 20 MW in size. Plants between 20 and 100 MW will typically be tapped off a 230 or 115 kV transmission line. This design will typically include line switches added to the main line on either side of the tap, a single radial breaker in the tap line, and a transfer trip scheme for faults anywhere on the main or tap line. DEP will typically build and own the transmission tap line and the breaker station adjacent to the generator substation. To connect to the DEP 500 kV system, a generating plant must be at least 500 MW.

If the total generation at a single site (or within a one mile radius) exceeds 100 MW, then a full transmission switching station (e.g. a three-breaker ring bus) will be required. If the total tapped generation along an entire line exceeds 200 MW, then a full transmission switching station (e.g. a three-breaker ring bus) will be required somewhere on the line (location to be determined on a case-by-case basis considering specific local conditions). If a generating plant connects to a DEP switching station, the generator owner will typically build and own the radial transmission line from the generating plant to the DEP switching station.

For additional details, refer to the DEP Facility Connection Requirements located under Generator Interconnection Information at the DEP OASIS website[23].

Constrained Areas in DEP

For DEP, the constrained area map (Attachment 1) represents areas of the DEP transmission system where additional generator interconnections have a high likelihood (depending on ultimate development decisions) of causing transmission problems requiring significant, expensive, and long-lead-time transmission upgrades. The constrained areas were determined by Transmission Planning from prior studies and knowledge of the DEP transmission system. Generator interconnections in regions that are not identified as constrained are not guaranteed to be without transmission problems. Studies will

[22] https://ezmt.anl.gov/
[23] https://www.oasis.oati.com/cpl/index.html

determine if there are any issues requiring transmission upgrades caused by generator interconnection requests in areas not identified as constrained.

In the greater Cumberland and Richmond County regions of North Carolina, extending across the state line into much of DEP's service territory in South Carolina, significant solar generation additions in the 2014-2017 timeframe, on both the transmission and distribution systems, have loaded the DEP transmission system to its limits. Any new generation in this area will cause transmission line overloads. Identified solutions exceed $100 million in transmission upgrades and would take at least 4 years to complete.

In the greater Brunswick County region of North Carolina, existing limits on the transmission system can cause limitations in operation of the Brunswick nuclear generators. These thermal and dynamic stability limitations require that the output of the Brunswick nuclear generators be substantially reduced following the outage of any one transmission line in the area. This includes forced outages or planned maintenance outages of transmission lines in the Brunswick County region. Any additional generation in this region would cause additional, unacceptable limitations in operation of the Brunswick nuclear generators without the addition of costly transmission solutions. The estimated cost of the identified transmission solution for this issue exceeds $100 million and would take at least 5 years to complete.

A DEP constrained infrastructure list is available that documents the individual transmission lines and substations that are in the constrained area.

Additional transmission line mapping information can be found at the Energy Zones Mapping Tool website[24].

Connecting Smaller Generators to the DEC and DEP Distribution Systems

Guidelines for the connection of smaller generators to the DEC and DEP Distribution Systems are provided in the Duke Energy Method of Service Guidelines[25]. In general, projects between 10 and 20 MW may be able to connect directly to a retail substation depending the voltage class of the distribution circuit, the voltage class of the transmission line serving the retail station, and other specific local factors described in the guidelines. Projects less than 10 MW may be able to connect to a general distribution circuit depending the voltage class of the distribution circuit, the voltage class of the transmission line serving the retail station, and other specific local factors described in the guidelines.

[24] https://ezmt.anl.gov/
[25] https://www.duke-energy.com/home/products/renewable-energy/generate-your-own

Exhibit 2

Attachment 1
DEC and DEP Constrained Areas

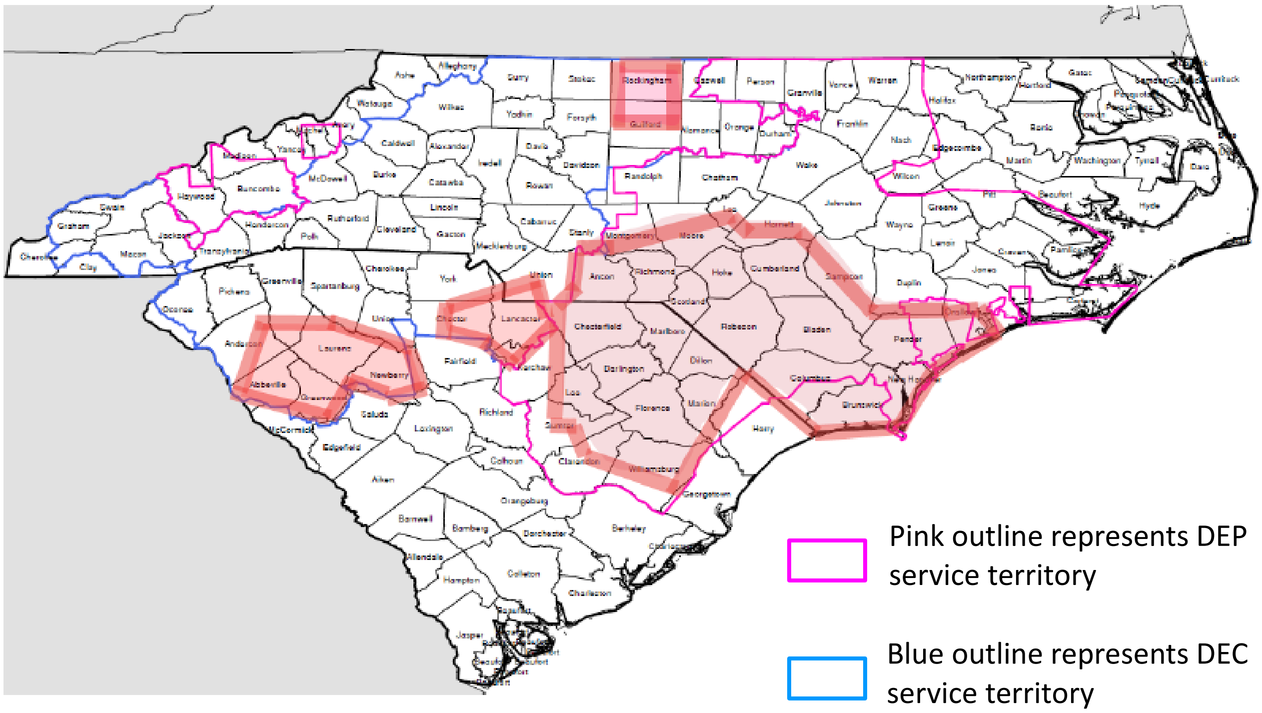
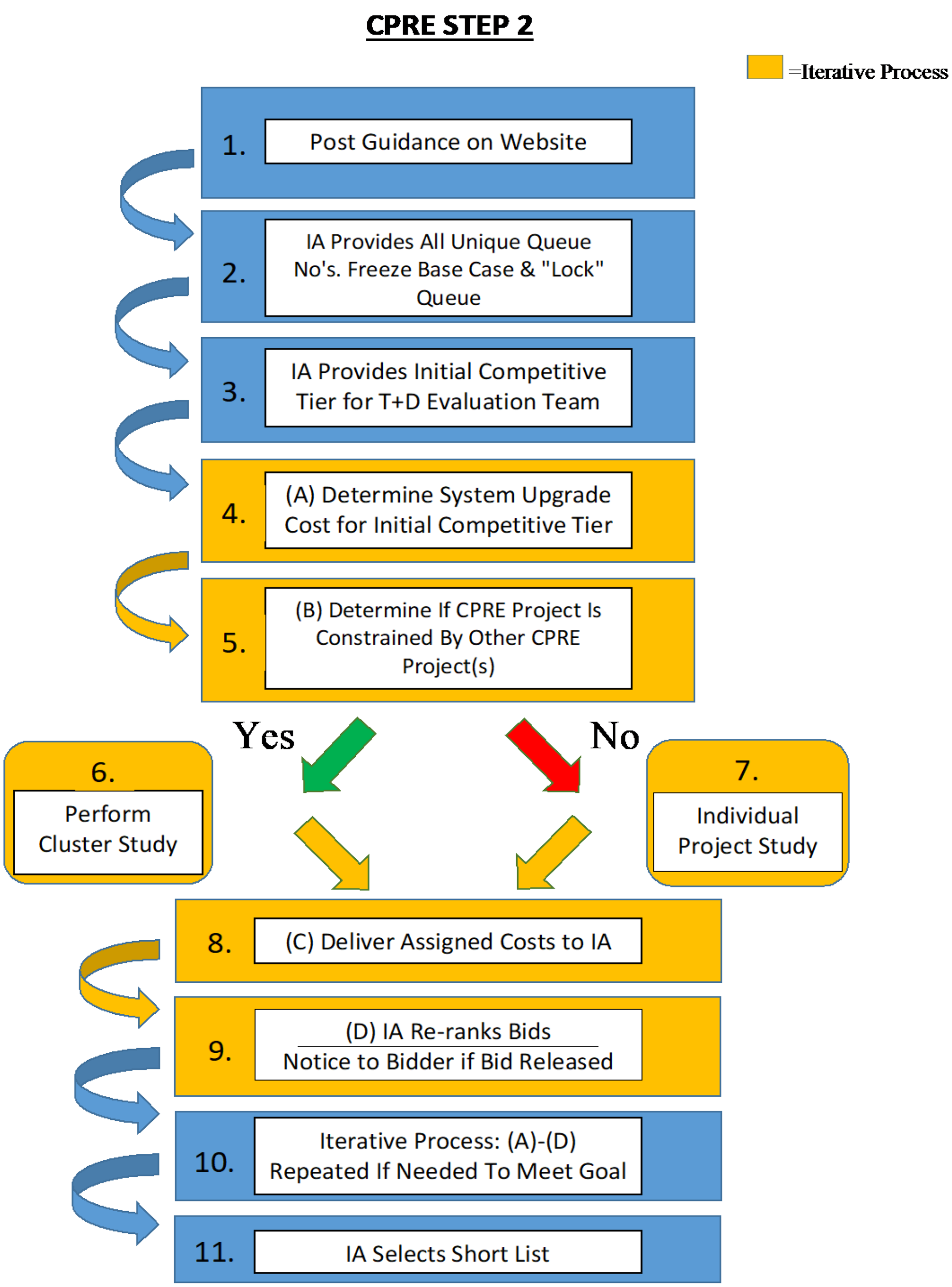


Exhibit 2

APPENDIX C

FLOW CHART OF STEP 2 ITERATIVE PROCESS



ATTACHMENT 1
TRANCHE 1 FINAL RESULTS
Report page 3

DEC

Proposal #	Contracting Party	Parent Company	Location	MWs AC	Storage Included ?
118-01	Partin Solar, LLC	Southern Current, LLC	Elkin, NC	50	
143-06	Carolina Solar Power, LLC	Duke Energy Renewables	Cleveland County, NC	50	
83-07	Duke Energy Carolinas, LLC	Duke Energy	Catawba County, NC	69.3	
60-01	X-Elio Energy SC York, LLC	X-Elio North America INC	York, SC	30	
57-23	Sugar Solar, LLC	Cypress Creek Renewables	Yadkinville, NC	60	
336-02	Westminster PV1, LLC	Ecoplexus, Inc.	Rutherfordton, NC	75	✓
336-01	Oakboro PV1, LLC	Ecoplexus, Inc.	Oakboro, NC	40	✓
143-04	Carolina Solar Power, LLC	Duke Energy Renewables	Surry County, NC	22.6	
83-06	Duke Energy Carolinas, LLC	Duke Energy	Gaston County, NC	25	
258-02	JSD Management, LLC	JSD Management, LLC	Woodruff, SC	20	
143-05	Carolina Solar Power, LLC	Duke Energy Renewables	Cabarrus County, NC	22.6	
			DEC Total:	**464.5**	

DEC Winning Proposals that Withdrew

Proposal #	Contracting Party	Location	MWs AC	Storage Included?
93-01	Stanly Solar, LLC	Albemarle, NC	50	

Exhibit 2

DEP

Proposal #	PPA Contracting Party	Parent Company	Location	MWs AC	Storage Included?
67-1	Cardinal Solar, LLC	National Renewable Energy Corporation	Marion, SC	7.02	
188-1	Trent River Solar, LLC	Silver Creek Intermediate, LLC	Pollocksville, NC	78.7	
			DEP Total:	**85.72**	

DEP Winning Proposals that Withdrew

Proposal #	Contracting Party	Location	MWs AC	Storage Included?
95-2	Duke Energy Carolinas, LLC	Richlands, NC	79.8	

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Exhibit 3

<u>Draft Tranche 2 RFP</u>

Exhibit 3

REQUEST FOR PROPOSALS FOR THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY PROGRAM TRANCHE 2

DUKE ENERGY CAROLINAS, LLC
DUKE ENERGY PROGRESS, LLC

Dated: October 15, 2019
Proposals Due: December 15, 2019

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I. PROGRAM OVERVIEW

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") are soliciting proposals for new renewable energy projects in support of the Companies' Competitive Procurement of Renewable Energy ("CPRE") Program ("Program").[1] The CPRE Program is being implemented in accordance with N.C. Gen. Stat. § 62-110.8, as enacted by North Carolina Session Law 2017-192 ("HB 589"), the North Carolina Utilities Commission's ("Commission" or "NCUC") Rule R8-71 ("CPRE Rule"), and the Commission's Order Modifying and Accepting CPRE Program Plan dated July 2, 2019, in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 ("Tranche 2 Order"). Capitalized terms not otherwise defined herein shall have the meaning set forth in the NCUC Rule R8-71(b).

This Tranche 2 Request for Proposals ("RFP") is soliciting approximately 600 megawatts ("MW") of new renewable energy resources in DEC and approximately 80 MW of new renewable energy resources in DEP.[2] Eligible Market Participants ("MPs") for this RFP include third-party renewable developers ("Third-Party MPs"), the DEC/DEP Proposal Team (as further described herein), and any affiliate of DEC or DEP that elects to submit a Proposal. Proposals submitted into the RFP ("Proposals") must be submitted in one of the following Proposal categories (as further described herein): (1) a Power Purchase Agreement ("PPA"), (2) Utility Self-Developed Facility (as further described herein), or (3) Asset Acquisition (as further described herein).

Tranche 2 is soliciting Proposals for electric generating facilities (each a "Facility") that meet all of the following requirements:

1. (i) In the case of Proposals submitted into the DEC portion of the RFP, are located in the DEC North Carolina or South Carolina service territory and have requested to physically interconnect with the DEC transmission or distribution systems; and (ii) in the case of Proposals submitted into the DEP portion of the RFP, are located in the DEP North Carolina or South Carolina service territory and have requested to physically interconnect with the DEP transmission or distribution systems.

[1] For the avoidance of doubt, the DEC and DEP portions of this RFP will be separately administered for purposes of ranking and selection.

[2] Given that the optimal portfolio may not align exactly with the MW target for DEC or DEP, the IA may recommend a portfolio within a range of +/- 10%. This approach will avoid the potential for foregoing an attractive Proposal that because it is the next-best ranked Proposal, would cause the portfolio to exceed the solicitation goal. In addition, the IA may consider any project size range provided by MPs in designing a portfolio that most closely meets the Tranche 2 target (see Section II(B)). In the event the IA determines a Proposal will be recommended for the final portfolio in an amount less than the maximum size proposed by an MP, the IA will confirm the MP's commitment to proceed with the Proposal at the size identified by the IA.

2. Have not been placed in service prior to the date of issuance of this RFP and be capable of completing Facility construction (not completion of interconnection) by January 1, 2022.[3]
3. Are sized between 1 MW and 80 MW (based on the inverter nameplate rating)). A Facility must have a single point of interconnection ("POI").
4. Use a renewable energy resource identified in G.S. 62-133.8(a)(8) and have demonstrated an adequate fuel supply from a qualifying resource.[4] Wind, swine, and poultry waste powered facilities will not be accepted.
5. Commit to sell 100% of its renewable electrical energy, capacity, and environmental and renewable attributes to DEC or DEP (as applicable).
6. In the case of PPA Proposals and Asset Acquisition Proposals, have submitted Form 556 to the Federal Energy Regulatory Commission on or before the date of submission of the Proposal to obtain qualifying facility ("QF") certification.
7. In the case of PPA Proposals and Asset Acquisition Proposals, have either (i) obtained a queue number under the North Carolina Interconnection Procedures ("NCIP") or the South Carolina Generator Interconnection Procedures ("SC GIP") to interconnect to the DEC transmission or distribution systems in the case of Proposals submitted into the DEC portion of the RFP or the DEP transmission or distribution system in the case of Proposals submitted into the DEP portion of the RFP; or (ii) where a Facility has previously submitted a FERC-jurisdictional interconnection request has submitted a Jurisdictional Interconnection Transition Request Form.[5]
8. In the case of Facilities that include energy storage, have all storage located on the DC side of the inverter and charged solely from the applicable Facility.

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3 For the avoidance of doubt, an MP is not required to obtain a certificate of public convenience and necessity ("CPCN") to construct the facility prior to submitting a PPA Proposal, but will be required to establish a reasonable plan for obtaining all necessary permits and certificates (including a CPCN) in a timely manner.

[4] "Renewable energy resource" means a solar electric, solar thermal, wind, hydropower, geothermal, or ocean current or wave energy resource; a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane; waste heat derived from a renewable energy resource and used to produce electricity or useful, measurable thermal energy at a retail electric customer's facility; or hydrogen derived from a renewable energy resource. "Renewable energy resource" does not include peat, a fossil fuel, or nuclear energy resource. As noted above, not all of these technologies are being solicited in Tranche 2.

[5] Interconnection requests for Facilities where the MP plans to contractually commit to sell the full output of the Facility to the interconnected utility, as required under the CPRE Program, are subject to the jurisdiction of, and interconnection procedures and agreements established by either the NCUC and South Carolina Public Service Commission. MPs with generating facilities that have previously submitted interconnection requests pursuant the Companies' Joint Open Access Transmission Tariff shall be allowed to retain their queue position while transitioning to become state jurisdictional interconnection customers of DEC or DEP (as applicable) prior to the CPRE RFP Solicitation bid due date. The Jurisdictional Interconnection Request Form has been made available on the IA RFP Website and contains further details regarding the transition process.

A. INDEPENDENT ADMINISTRATOR

This RFP will be administered by an Independent Administrator, the Accion Group, LLC ("Accion" or the "IA"). Accion is responsible for developing and utilizing the CPRE Program Methodology to evaluate all Proposals in accordance with the evaluation process established under NCUC Rule R8-71(f)(3)(iii), as further described herein, and ensuring that all Proposals are treated equitably throughout the RFP.

B. RFP ACCESS AND INSTRUCTIONS

Accion hosts a website ("IA RFP Website") that serves as the required vehicle for all RFP communications. Respondents and interested parties must be registered on the IA RFP Website to access further information related to the RFP. The IA RFP Website may be accessed at https://decprerfp2019.accionpower.com.

The IA RFP website will also be used for registered parties to provide comments on or before August 30, 2019 regarding this RFP document, the pro forma PPA, and the various Asset Acquisition agreements. In addition, registered parties may submit questions concerning the RFP on the "Q&A" page of IA RFP Website. The questions and responses will be posted for viewing by all persons registered on the IA RFP Website. Finally, the IA RFP Website also has a confidential "message board" available to registered MPs to facilitate project-specific questions to the IA that should not be disclosed to all MPs. The IA will review all questions and messages and solicit information from the Evaluation Team, as necessary, without disclosing the identity of the MP posing the request. Questions and responses that the IA determines are appropriate for disclosure to all registered MPs will be posted in the Q&A page. After the Proposal submission date, the confidential message board will be used should the IA need clarification concerning any Proposal.

Proposals and all associated documentation must be submitted to the IA through the IA RFP Website on or before **12:00 pm EDT (Noon) on December 15, 2019.**

C. TRANCHE 2 RFP SCHEDULE

The table below presents the planned Tranche 2 RFP schedule. As provided in the CPRE Rule, the Tranche 2 RFP schedule may be modified after consultation with and approval by the IA. MPs will receive notification of any schedule changes through the IA RFP Website.

Milestone	Date
August Stakeholder Meeting	08/07/2019
Draft RFP documents posted to IA Website	08/15/2019
Bidder Conference and September Stakeholder Meeting	09/12/2019
Comment period on draft RFP documents closes	08/30/2019
PPA filed with NCUC	09/15/2019
IA report re: RFP documents	09/25/2019
October Stakeholder Meeting	10/10/2019
Final RFP documents posted to IA website and RFP Opens	10/15/2019
November Stakeholder Meeting	11/13/2019
December Stakeholder Meeting	12/12/2019
Deadline for submission of Proposals	12/15/2019[6]
Projected Conclusion of Step 1 of the Evaluation Process	03/01/2020
Projected Conclusion of Step 2 and winning bids notified	06/30/2020
Projected Conclusion of Contracting period	08/28/2020

D. SEPARATION PROTOCOLS

The IA will ensure compliance with the communication restrictions and other requirements set forth in NCUC Rule R8-71(e) (the "Separation Protocols"). Pursuant to such CPRE Rule, DEC and DEP have collectively established a team that is responsible for preparing bids on behalf of DEC/DEP (such team, the "DEC/DEP Proposal Team"), and Duke Energy Renewables, Inc. ("DER") has established a separate team that is responsible for preparing bids on behalf of DER (such team, the "DER Proposal Team" and together with the DEC/DEP Proposal Team, the "Proposal Teams"). In addition, DEC and DEP have established a team that is responsible for assisting the IA in developing the RFP and evaluating Proposals (the "Evaluation Team"). Finally, the Evaluation Team has a sub-team responsible for assessing and assigning system upgrade costs to Proposals (the "T&D Sub-Team"). The IA will provide the T&D Sub-Team with the identity of each MP and the Facility to be studied during the Step 2 process. There will also be a sub-team responsible for credit review as part of the completion of Step 2 (the "Credit Sub-Team"). All members of the Proposal Team(s) and the Evaluation Team have been separately identified in writing to the IA and physically segregated for purposes of all activities that are part of the Tranche 2 RFP solicitation process. All Proposal Team and Evaluation Team members have also been required to execute acknowledgements regarding compliance with the Separation Protocols, which have been provided to the IA. As shown in the Tranche 2 RFP Schedule above, the IA will require that the Proposal Teams submit any Proposals no less than 24 hours before the RFP window closes.

E. CONFIDENTIALITY

[6] This date is subject to modification in accordance with the Commission's Tranche 2 Order.

The IA will not publicly disclose the identity all MPs during the Step 1 and Step 2 evaluation process. However, at the conclusion of the Step 2 evaluation, upon selection of winning MPs, the IA and/or Duke shall be permitted to publicly identity all CPRE participants that submit Proposals in response to any Commission-directed reporting requirements.

II. GENERAL TERMS

A. PROPOSAL CATEGORIES

Proposals may be structured using one of the three proposal categories ("Proposal Categories") defined in the following table:

Proposal Type	Proposal Cost Structure
PPA	Levelized (non-escalating) payments for capacity, energy, and environmental and renewable attributes in $/MWh terms for 20 years from the commercial operation date. The pro forma PPA is attached as **Appendix A**.
Utility Self-Developed Facilities	Utility owns or controls the property and offers Renewable Resource facility(s) into the CPRE RFP in $/MWh terms for 20 years from the commercial operation date.
Asset Acquisition	**Asset Transfer plus EPC** – The Facility is submitted into the RFP for purchase by DEC/DEP along with an offer to build the site under an Engineering Procurement and Construction Agreement ("EPC") for purchase by DEC or DEP. Facility is developed by the MP and ownership transfers to DEC or DEP before the start of construction.
	Build Own Transfer ("BOT") – Facility is fully developed and constructed by the MP and submitted as a "turn-key" offer into the RFP by MP. Facility ownership will be transferred to DEC or DEP prior to commercial operation.
	Asset Transfer – Facility siting, land control, design, permitting, and interconnect studies completed by the MP and fully-developed project offered into the RFP. Facility ownership will be transferred to DEC or DEP prior to construction and DEC or DEP will be responsible for construction.

B. PROPOSAL ALTERNATIVES AND SIZE FLEXIBILITY

MPs may submit Proposals for the same Facility proffering different sizing, pricing or technology. (e.g., a Facility that is proposed both with and without energy storage must submit separate

Proposals for each Facility configuration). Each Proposal will be a separate submission subject to a separate Proposal Fee. A MP may submit the same Facility as both an Asset Acquisition Proposal and as a PPA Proposal, and that would constitute two separate Proposals. If the Asset Acquisition Proposal is sponsored by the DEC/DEP Proposal Team, the Acquisition Proposal will be converted to PPA pricing as more specifically discussed below. In such case, the highest ranking of all Proposals for the Facility, based on the IA's evaluation, will be considered the "best" or controlling proposal for such Facility and the IA shall eliminate the other Proposal from further consideration in the RFP.

MPs will be permitted to identify the minimum size of the Facility (up to a 10% maximum reduction)[7] that the MP is willing to provide at the same $/MWh price. For example, for a 50 MW Proposal, the MP could indicate that it is willing to deliver a Facility sized anywhere between 45-50 MW for the same $/MWh price.

C. MARKET PARTICIPANTS AND PROPOSAL SPONSORS

DEC and DEP recognize that MPs may utilize partners or sponsors ("Proposal Sponsors") for Proposal development. Proposals that rely on Proposal Sponsors to meet RFP requirements must provide evidence that is satisfactory to the IA of a binding legal partnership or similar relationship with such Proposal Sponsor.

Historically underutilized businesses are encouraged to participate in the RFP. The definitions to be employed for such purposes are set forth in **Appendix B** to this RFP. MPs shall not discriminate based upon race, religion, color, national origin, age, sex, or handicap.

D. PROPOSAL FEES

Each MP is required to submit with each Proposal a non-refundable "Proposal Fee" of $500/MW, based on the Facility's nameplate capacity, up to a maximum of ten thousand dollars ($10,000). In addition, successful MPs will be responsible for a pro-rata share of the Winners' Fee (as hereinafter defined).

Proposal Fees are non-refundable and for the avoidance of doubt, will not be refunded in the case of any modification of this RFP schedule, rejection of any Proposal, or failure by a winning MP to execute a PPA. Proposal Fees must be paid via electronic payments through Accion's website: https://decprerfp2019.accionpower.com. Payment is due at the time of Proposal submission and must be received no later than 12:00 PM EDT (Noon) on the Proposal due date. Failure to submit the Proposal Fee will result in automatic disqualification of the Proposal from further consideration.

[7] The maximum reduction percentage is based on Section 1.5.1.6 of the NCIP and Attachment 1 of the SC GIP.

E. WINNERS' FEE

The "Winners' Fee" is the amount to be determined as described below in order to recover any remaining IA costs not covered by the Proposal Fee. The Winners' Fee will be determined upon conclusion of the RFP. Any such Winners' Fee costs will be allocated among all winning Proposals selected by both DEC and DEP on a pro-rata basis on a per MW basis. The total of the Winners' Fees shall not exceed one million dollars ($1,000,000.00).

F. STEP 2 PROPOSAL SECURITY

1. Third-Party MPs and DER Proposal Team

Security in the amount of $20/kW, based on the Facility's inverter nameplate capacity, must be posted by all Third-Party MPs and the DER Proposal Team submitting PPA Proposal that are selected to move into Step 2 of the evaluation process ("Step 2 Proposal Security"). This Step 2 Proposal Security can be in the form of (i) cash; (ii) a Surety Bond; or (iii) a Letter of Credit ("LOC"), in each case, in a form acceptable to the Companies and issued by an entity that meets the Companies' issuer requirements and naming DEC or DEP (as applicable) as the sole beneficiary. An issuing bank for the LOC must have a minimum credit rating of A- from S&P and A3 from Moody's and a surety must be rated A.M. Best "A- VII" or higher. Surety bonds must be irrevocable and require payment by the surety within ten days of demand. Interest will not be paid on cash deposits. An example of acceptable LOC is provided in **Appendix C** and an acceptable surety bond is provided in **Appendix D**.

The IA will provide notification to an MP when the IA determines it will likely select the Proposal to move into the Step 2 evaluation. Within 14 days of such initial notification, MPs are required to provide draft forms of Proposal Security, if not posting cash, to allow sufficient time for the IA and the Companies to review and confirm the Proposal Security materially conform to the forms provided in **Appendix C** and **Appendix D**, respectively. The IA will then notify the MP when the Proposal is formally moved into the Step 2 Evaluation, at which point, the MP must post the Step 2 Proposal Security within seven business days[8].

2. DEC/DEP Proposal Team

In the case of Asset Acquisition Proposal sponsored by the DEC/DEP Proposal Team, Step 2 Proposal Security will be required from the Third-Party MP as further described in Section III(C).

In the case of Utility Self-Developed Facilities, the DEC/DEP Proposal Team will be required to acknowledge that in the event such Proposal is selected as a winner and fails to execute the

[8] As indicated in the schedule in Section I(c), the Companies currently expect that Step 1 of the evaluation process will be completed on or around March 1, 2020.

Acknowledgment Form, an amount equal to $20/kW will be disallowed from the applicable CPRE Rider recovery.

3. Step 2 Proposal Security Administration

The Step 2 Proposal Security will be released (i) if the Proposal is eliminated by the IA due to failure to meet any required RFP criteria or action; (ii) if the Proposal is not selected as a winning proposal, upon closure of the contracting period; or (iii) if the Proposal is selected as a winning Proposal, upon completion of the contracting phase of the RFP, including execution of the applicable contract (PPA or APA) and posting of security as required in the applicable agreement. DEC or DEP (as applicable) will be entitled to draw on the full amount of the Step 2 Proposal Security in the event that the MP (a) withdraws its Proposal during Step 2 of the Evaluation Process; or (b) if the Proposal is selected as a winning Proposal but the MP fails to complete the contracting phase.

III. ADDITIONAL PROPOSAL REQUIREMENTS

A. SELF-DEVELOPED, SUBSIDIARY, AND AFFILIATE PROPOSALS

Utility Self-Developed Proposals and conversions of Asset Acquisition Proposals will be bid using the same templates, forms, and pricing requirements applicable to PPA Proposals. Proposals submitted by the DER Proposal Team will be made via the IA Website and meet the same requirements as Proposals from Third-Party MPs. In accordance with G.S. 62-110.8(b)(4), no more than thirty percent (30%) of the total CPRE procurement requirements can be awarded to Facilities in which DEC, DEP, or any subsidiary or affiliate holds an ownership interest at the time of Proposal submission.

Utility Self-Developed Proposals and conversions of Asset Acquisition Proposals will be priced based on the assumption that these facilities will continue to receive market-based revenues based on a pricing mechanism to be established by the Commission at the conclusion of the initial 20-year term of the PPA.

B. PPA PROPOSALS

All PPA Proposals must meet the technical specifications set forth in the PPA, as determined by the IA (in consultation with the Evaluation Team, as necessary). The pro forma PPA is provided as Appendix A. After closure of the RFP comment period, and subsequent filing of the PPA with the NCUC, the pro forma PPA is not subject to negotiation or adjustment for purpose of Tranche 2.

C. ASSET ACQUISITION PROPOSALS

Third-Party MPs are permitted to submit Asset Acquisition Proposals for DEC/DEP to consider acquiring a proposed Facility. In Tranche 2, only solar photovoltaic Facilities that are 20 MWac or greater will be accepted for consideration as Asset Acquisitions. As discussed above, Third-Party MPs may submit PPA Proposals as well as Asset Acquisitions for the same Facility, but each Proposal Category must be submitted as a separate Proposal.

Asset Acquisition Proposals must be priced on a $/kw nameplate capacity basis to be paid according to payment milestones set forth under each type of Asset Acquisition Proposal. All Proposals must meet the DEC/DEP Proposal Team's technical design specifications, as provided in definitive agreements, including complying with the DEC/DEP Proposal Team's list of approved vendors/suppliers (provided on the IA Website for review). After submission of an Asset Acquisition Proposal by an MP, the DEC/DEP Proposal Team will consider all aspects of the Proposal, including location, size, viability, technology, and price to determine if the DEC/DEP Proposal Team will sponsor the Asset Acquisition Proposal. Should the DEC/DEP Proposal Team elect to sponsor an Asset Acquisition Proposal, the DEC/DEP Proposal Team will coordinate with the MP and submit a Proposal into the CPRE RFP in on a $/MWh basis utilizing the percentage decrement structure described in Section IV below. All Asset Acquisition contracts (definitive agreements under which the MP and DEC/DEP will transact) and exhibits related thereto (including the DEC/DEP Proposal Team's technical design specifications), will be available on the IA RFP website for review and comment by MPs. The DEC/DEP Proposal Team will review and consider any proposed changes (in the form of redlines) to its Asset Acquisition contracts that are submitted at the time an Asset Acquisition Proposal is submitted. The DEC/DEP Proposal Team will not, in any event, consider any proposed changes to the Asset Acquisition contracts, or exhibits related thereto (including the DEC/DEP Proposal Team's technical design specifications), from an MP that are not submitted along with Asset Acquisition Proposal. If the DEC/DEP Proposal Team decides to sponsor one or more Asset Acquisition Proposal(s), the DEC/DEP Proposal Team will require the applicable MP execute a term sheet relating to the principal commercial terms of the Asset Acquisition Proposal and acknowledging that no further changes to the Asset Acquisition Contracts (other than those noted at the time of Proposal Submission) will be accepted, and the DEC/DEP Proposal Team will then submit to the IA the Proposal, for consideration in Step 1 of the evaluation process on a $/MWh basis utilizing the percentage decrement structure described in Section IV below. Any such Proposals would then be evaluated by the IA along with all other PPA and Utility Self-Developed Proposals submitted. At no time during this process will the DEC/DEP Proposal team have access to any information from the IA Website, including pricing, for PPA Proposals submitted by any Third-Party MPs.

For solar photovoltaic Facilities, additional guidance relating to the DEC/DEP Proposal Team's PV facility design and Proposal criteria will be provided on the portion of the IA RFP Website section dedicated to Asset Acquisition Proposals.

MPs will be required to complete a proposal form that includes detailed information for each Facility, including a list of all major equipment included in the Asset Acquisition Proposal, including manufacturer name and equipment type for all panels, inverters, and racking supply. All Asset Acquisition Proposals should include product data sheets, product warranty information, and the design criteria that forms the basis of the pricing proposal. The DEC/DEP Proposal Team will review project design criteria to properly evaluate the quality of the project design and scope of work included in the proposal price and conformance with the design specifications.
For MPs submitting Asset Acquisition Proposals that do not wish to construct the Facility, the DEC/DEP Proposal Team will only consider Facilities that have completed System Impact Studies, secured long-term site control, initiated or obtained requisite project permits, completed a Phase I Environmental Site Assessment, conducted site analysis (including wetland delineation, preliminary geotechnical analysis, and boundary surveys), prepared a preliminary site layout, obtained CPCN approval (if applicable), and provided all additional required information as identified on the IA RFP Website to allow for full and proper evaluation of the project attributes.
For all Asset Acquisition Proposals, MPs must identify which portion of the capital costs are ITC eligible and provide details of any property tax abatement or exemption or fee in lieu of tax (FILOT) arrangements or eligibility for other grants or tax credits. MPs must identify the portion of capital costs that belong to each federal tax depreciation class.

Interconnection Facilities (as defined herein) cost estimates must be included as an additional project cost and documented in the Proposal.

MPs submitting Asset Transfer plus EPC or a BOT (but not if proposing an Asset Transfer only) must have completed or directly managed the completion of the development, engineering, equipment procurement, and construction of at least 50 MW of solar facilities within the United States or Canada. For all Asset Acquisitions, MPs must provide sufficient financial assurances, as set forth in the form EPC and BOT agreements, as necessary for the Facility to meet schedule and proposed performance milestones. In addition, MPs must provide evidence of at least one recent successful construction financing completed by the MP of comparable size to the submitted proposal.

The Third-Party MP that submitted the Asset Acquisition Proposal will be required to provide Step 2 Proposal Security in accordance with the notification and timing requirements described in Section II(F)(1). For Asset Transfer plus EPC and BOT proposals, the Step 2 Proposal Security is \$20kWac. For Asset Transfer proposals, the Step 2 Proposal Security is the amount of the purchase price of the Proposal. Such Step 2 Proposal Security must conform with the requirements of Section II(F)(1) and will administered in accordance with Section II(F)(3).

IV. AVOIDED COST THRESHOLD AND PROPOSAL PRICING

All PPA and Utility Self-Developed Facility Proposals must be submitted using levelized 20-year dollar per megawatt-hour ($/MWh) pricing, and, as discussed above, the DEC/DEP Proposal Team will convert any Asset Acquisition Proposals selected into levelized 20-year dollar per megawatt-hour ($/MWh) pricing.

All Proposals (including the cost of System Upgrades as described herein) must be at or below the applicable 20-year dollar per megawatt-hour ($/MWh) avoided cost rates specified in the tables below.

<u>Avoided Costs Threshold for Tranche 2</u>

Note: All pricing is indicative and subject to adjustment based on the Commission's final order in Docket No. E-100, Sub 158. Subject to the Commission's approval, the Companies intend to apply the Solar Integration Services Charge to Tranche 2 CPRE PPAs but have not yet determined the operating protocols that will allow MPs to avoid such charge. This issue will be discussed in more detail at future stakeholder meetings.

ENERGY

DEC-Stipulated Energy Rate Design Method Estimation of 20 YR CPRE (2022-2041)

Independent Energy Price Blocks		1.Summer Premium Peak (PM)	2.Summer On-Peak (PM)	3.Summer Off-Peak	4. Winter Premium Peak (AM)	5.Winter On-Peak (AM)	6.Winter On-Peak (PM)	7.Winter Off-Peak	8.Shoulder On-Peak	9.Shoulder Off-Peak
		($/Mwh	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)
Distribution	20 Year	57.1	56.4	34.7	80.7	61.2	67.6	40.9	46.3	31.9
Transmission	20 Year	55.0	54.5	34.0	78.2	59.6	65.9	40.1	45.4	31.4

DEC	HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)		Off												On (pm)				Premium				On (pm)		Off	
Winter (Dec-Feb)		Off					On (am)	Premium			On (am)	Off							On (pm)					Off	
Shoulder (Remaining)		Off						On				Off						On							Off

CAPACITY

DEC-Stipulated Capacity Rate Design Method Estimation of 20 YR CPRE (2022-2041)

Independent Price Blocks		1.Summer On	2.Winter On (am)	3.Winter On (pm)
		($/Mwh)	($/Mwh)	($/Mwh)
Distribution	20 Year	16.9	78.7	25.5
Transmission	20 Year	16.5	76.6	24.8

DEC / DEP	HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jul - Aug)																		On							
Winter (Dec - Mar)								On (am)												On (pm)					

ENERGY										
DEP-Stipulated Energy Rate Design Method Estimation of 20 YR CPRE (2022-2041)										
Independent Energy Price Blocks		1.Summer Premium Peak (PM)	2.Summer On-Peak (PM)	3.Summer Off-Peak	4. Winter Premium Peak (AM)	5.Winter On-Peak (AM)	6.Winter On-Peak (PM)	7.Winter Off-Peak	8.Shoulder On-Peak	9.Shoulder Off-Peak
		($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)
Distribution	20 Year	43.9	43.7	36.8	59.6	44.7	52.2	37.2	39.3	28.1
Transmission	20 Year	42.7	42.6	36.3	58.2	44.0	51.2	36.7	38.8	27.9

DEP	HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)		Off													On (pm)			Premium			On (pm)	Off			
Winter (Dec-Feb)		Off				On (am)		Premium			On (am)		Off							On (pm)				Off	
Shoulder (Remaining)		Off					On					Off							On						Off

CAPACITY							
DEP-Stipulated Capacity Rate Design Method Estimation of 20 YR CPRE (2022-2041)							
Independent Price Blocks		1.Summer On		2.Winter On (am)		3.Winter On (pm)	
		($/Mwh)		($/Mwh)		($/Mwh)	
Distribution	20 Year	0.00		135.7		58.2	
Transmission	20 Year	0.00		133.1		57.1	

DEC / DEP	HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jul - Aug)																		On							
Winter (Dec - Mar)								On (am)												On (pm)					

<u>Seasonal Hourly Capacity Definitions</u>

- All Capacity Periods include Monday through Sunday

<u>Seasonal Hourly Energy Definitions</u>

- All On-Peak Periods include Monday through Friday, except for Holidays.
- Off-Peak Periods include Saturday and Sunday, and all Holidays.
- Holidays include: New Year's Day, Memorial Day, Good Friday, Independence Day, Labor Day, Thanksgiving Day, Day after Thanksgiving, and Christmas Day.

Proposal pricing must be in the same format of 20-year avoided cost pricing periods as shown in the tables above. Proposal pricing must be stated as an equal percentage decrement that is applied equally to all pricing periods. For example, an MP could propose pricing that is 10% less than the avoided cost in each pricing period. This format for pricing will be required for the bid entry on the IA RFP Website and will be the basis for the pricing in the PPA. Translating this 10% proposed pricing decrement example into a levelized form of pricing, the following would be the result for a desired 10% decrement for all pricing periods for a Transmission connected project in DEC:

ENERGY

DEC-Stipulated Energy Rate Design Method Estimation of 20 YR CPRE (2022-2041)

Independent Energy Price Blocks		1.Summer Premium Peak (PM)	2.Summer On-Peak (PM)	3.Summer Off-Peak	4. Winter Premium Peak (AM)	5.Winter On-Peak (AM)	6.Winter On-Peak (PM)	7.Winter Off-Peak	8.Shoulder On-Peak	9.Shoulder Off-Peak
		($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)	($/Mwh)
Distribution	20 Year	~~57.1~~ 51.4	~~56.4~~ 50.8	~~34.7~~ 31.2	~~80.7~~ 72.6	~~61.2~~ 55.1	~~67.6~~ 60.8	~~40.9~~ 36.8	~~46.3~~ 41.7	~~31.9~~ 28.7
Transmission	20 Year	~~55.0~~ 49.5	~~54.5~~ 49.1	~~34.0~~ 30.6	~~78.2~~ 70.4	~~59.6~~ 53.6	~~65.9~~ 59.3	~~40.1~~ 36.1	~~45.4~~ 40.9	~~31.4~~ 28.3

DEC	HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)		Off												On (pm)				Premium				On (pm)		Off	
Winter (Dec-Feb)		Off					On (am)	Premium		On (am)	Off								On (pm)					Off	
Shoulder (Remaining)		Off						On				Off						On							Off

CAPACITY

DEC-Stipulated Capacity Rate Design Method Estimation of 20 YR CPRE (2022-2041)

Independent Price Blocks		1.Summer On	2.Winter On (am)	3.Winter On (pm)
		($/Mwh)	($/Mwh)	($/Mwh)
Distribution	20 Year	~~16.9~~ 15.2	~~78.7~~ 70.8	~~25.5~~ 23.0
Transmission	20 Year	~~16.5~~ 14.9	~~76.6~~ 68.9	~~24.8~~ 22.3

DEC / DEP	Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jul - Aug)																		On							
Winter (Dec - Mar)								On (am)												On (pm)					

PPA pricing must include all project costs to the Point of Interconnection ("POI"), including the cost to directly connect to the existing DEC or DEP transmission/distribution system ("Interconnection Facilities"). Interconnection Facilities costs at the POI will include all DEC's or DEP's (as applicable) costs to connect the Facility to the existing transmission/distribution system delivery point, but shall not include the costs of upgrades to the transmission or distribution system beyond the POI. MP-owned equipment up to the POI often includes equipment such as the generator step-up transformer (for conversion up to the interconnecting voltage level), facility side generator breaker (as needed), and all station service equipment. Utility-owned equipment typically includes metering, protective equipment, relays, and other new electrical infrastructure and specific configurations for transmission connections as discussed in more detail below.

MPs with successful Proposals will be responsible for all Interconnection Facilities costs, even if the actual costs exceed the amount estimated by the MP. The IA will review the estimated Interconnection Facilities costs included in each proposal for reasonableness and reserves the right to impute a larger amount of Interconnection Facilities Costs where it determines that the Interconnection Costs assumed by the MP are unreasonably low. Should the IA determine imputed Interconnection Facilities Costs should be used, the MP will be advised and provided the opportunity to review the revised cost estimates with the IA and advise the IA of whether the imputed estimate is accepted by the MP.

The costs of transmission/distribution grid improvements and upgrades ("System Upgrades") should not be incorporated in the MP's PPA price. System Upgrade costs for all Proposals will be identified during Step 2 of the evaluation process as set forth in NCUC Rule R8-71(f)(3)(iii). For the avoidance of doubt, for purposes of determining the satisfaction of the avoided cost threshold, the System Upgrade costs determined by the T&D Sub-Team shall be converted to 20-year $/MWh pricing and incorporated into the Proposal price by the IA.

V. PROPOSAL EVALUATION

A. OVERVIEW

Proposals will be evaluated by the IA in accordance with the evaluation process set forth in NCUC Rule R8-71(f)(3). A copy of the CPRE Rule is provided on the IA RFP Website. As specified in NCUC Rule R8-71(f)(3), in Step 1 of the evaluation process, the IA will perform the initial ranking of Proposals based on a combination of economic and non-economic criteria. As a part of the Step 1 evaluation, the IA may allow a market participant an opportunity to modify or clarify its proposal to cure a non-conformance or non-substantive deficiency that would otherwise require elimination of the Proposal. The IA will provide the MP with written notice of the deficiency and the MP shall then have five (5) business days after receiving the written notice to cure the deficiency, where failure to cure the deficiency shall result in withdrawal of the Proposal from further consideration. Proposal Fees for a Proposal that fails to timely cure any deficiency identified by the IA shall not be returned.

Each Proposal will be evaluated on its benefit to the DEC/DEP system over the twenty-year analysis period on a $/MWh basis (accumulated net present value). Although an MP may enjoy economies of scale with respect to the owner's and development cost of a Facility, the evaluation will be conducted on a $/MWh (benefit to DEP/DEC) basis and therefore will not favor a Proposal based on Facility size. In order to assess a Proposal's net benefit, the evaluation must determine both the Proposal's cost and the Proposal's benefit to the DEC/DEP system. The cost of the Proposal is determined by taking the MP submitted $/MWh rate and applying the rate to the Facility's projected output (8760 hours x 20 years). The benefit to the DEC/DEP system is determined using two metrics: (1) the Proposal's output contributes toward the ability to defer future DEC/DEP generating unit capacity and (2) the Proposal's energy output replaces energy that would have been supplied at DEC/DEP system cost for that particular hour.

Proposals must include a set of 8760 hour output projections each of the 20 years of the term. Proposals must be accompanied by PVSyst inputs/outputs and supporting workpapers and calculations demonstrating the basis for the energy profiles proposed. Proposals that include storage must submit two sets of 8760 hour output projections (for the twenty years) for the facility design. The first set is the output projection assuming that the storage capability is not utilized (i.e., turned off) and the second set of output projections is the Facility output after utilizing the storage capability. It is assumed that the post-storage output projections reflect that the MP has optimized the use of the storage capability. The IA will review both the pre-storage and post-storage Facility output in order to determine that the post-storage projections are reasonable.

Note that under the terms of the PPA, DEP/DEC has the right to curtail energy from the Facility up to 10% of the Facility's annual energy production in the DEP jurisdiction and 5% in the DEC jurisdiction, without compensation to the Facility owner. For purposes of the evaluation, it will be assumed that DEP/DEC fully exercises the energy curtailment to the respective 5% and 10% limits. Note that the energy curtailment reduces the Facility's revenue (in that less energy is sold to the DEP/DEC grid).

In the Proposal evaluation, the curtailment methodology will optimize energy costs for DEP/DEC. In other words, the methodology will begin curtailing the Facility's output when the cost of the Facility's energy is most costly when measured against the DEP/DEC system cost for that hour. This methodology will continue (as the cost difference is reduced) until the full allotment of curtailment is reached (either 5% or 10%).

With Facilities that include storage, it is recognized that some of the Facility's energy that is "lost" during curtailment can be stored and sold into the DEP/DEC system several hours later. For purpose of the evaluation, the following limitations will be taken into account: the overall roundtrip efficiency of energy storage, the MW capability of the storage system (which may be smaller than the facility output), and the MWh (energy) capability of the storage system.

The non-economic criteria specified below will also be evaluated by the IA and scored in accordance with the scoring sheet attached hereto as **Appendix F**, which has been developed by the IA and sets forth the weighting the IA will use in determining the Step 1 ranking of all Proposals. The Step 1 evaluation ranked Proposals into an initial Competitive Tier ("Competitive Tier"), Competitive Tier Reserve ("Competitive Tier Reserve" or "Reserve List"), and released Proposals. For those Proposals that do not advance to Step 2 of the evaluation process, the IA will notify the relevant MP on or before the milestone for concluding Step 1 of the Evaluation Process identified in the Tranche 2 RFP schedule.

In Step 2 of the evaluation process, the T&D Sub-Team shall assess the system impact of the Proposals in the order ranked by the IA and assign any System Upgrade costs attributable to each such Proposal. The IA will utilize such information to re-rank the Proposals (as necessary), and this process will continue in an iterative manner until the optimal portfolio of Proposals has been identified.

Step 2 of the evaluation process shall utilize the System Impact Grouping Study[9] and all Proposals will be required to be studied based on the Queue Number established by the Companies for purposes of the System Impact Grouping Study.[10]

B. NON-ECONOMIC SCORING CRITERIA

The following non-economic criteria will be evaluated for each Proposal and scored in accordance with the scoring sheet.

1. Facility Permitting

MPs should disclose all permits that will have to be obtained and the status of each permit along with a timeline for the completion of all permits that relate to the Proposal. The site evaluation and studies conducted to date, as well as a timeline for completion of these studies, should be included in the Proposal.[11]

2. Financing Experience

Each Proposal should describe the plans for acquiring the necessary funds for developing, constructing, and operating the Facility. Such plans should include a discussion of the Facility's legal ownership structure and the expected sources and types of capital that the MP has committed to secure. If available, letters of interest or letters of commitment from such financial partners or key sources of funding should be provided.

For PPA proposals, MPs must be able to provide evidence of at least one recent successful facility financing completed of comparable size to the Proposal submitted within the last five years.

MPs must provide the financial and credit information set forth in **Appendix E**.

3. Technical Development and Operational Experience

In general, MP must show experience in developing and operating renewable facilities of comparable size and technology as the Facility submitted in the Proposal. More specifically, MP must:

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[9] As that term is utilized in the NCIP.

[10] The "Late-Stage Proposal" approved by the Commission for use in Tranche 1 has been eliminated for Tranche 2. The Companies will discuss at Stakeholder Meeting #2 the appropriate treatment of CPRE Proposals that have an executed Interconnection Agreement at the time of Proposal Submission, as was raised by an MP during Stakeholder Meeting #1.

[11] MPs should take reasonable steps to develop projects in a manner that protects the environment and the communities served by the Companies. According to the North Carolina Wildlife Resources Commission, increasing the availability of native plants at solar facilities can help support pollinators, including birds, bees, and other wildlife, benefiting nearby agricultural fields and community growers. Please consider following the "Solar Site Pollinator Habitat Planning & Assessment Form" provided in **Appendix G**.

- In the case of PPA proposals, have operated a renewable energy project or portfolio of projects >50 MW AC or 3x the nameplate capacity of the Proposal, whichever is less;
- In the case of solar Proposals, have completed or directly managed the completion of the development, engineering, equipment procurement, and construction of >50 MW or 3x the nameplate capacity of the Proposal, whichever is greater, of solar facilities, including at least one project of comparable size to the proposed facility within the United States or Canada; and
- In the case of non-solar Proposals, have completed or directly managed the completion of the development, engineering, equipment procurement, and construction of at least 10 MW of relevant renewable energy facilities within the United States or Canada.

4. Historically Underutilized Businesses

Historically underutilized businesses meeting the requirements set forth in **Appendix B** will be scored in accordance with the score sheet.

VI. ADDITIONAL INFORMATION

A. INTERCONNECTION TIMELINE AND PPA TERM

Typically, execution of an Interconnection Agreement is achieved approximately 4 – 6 months after completion of a System Impact Study. For transmission-connected projects, commercial operation of the Interconnection Facilities is achieved 18 – 24 months after execution of an Interconnection Agreement. However, it is important to note that the amount of time required for construction of Interconnection Facilities for transmission-connected projects can be substantially impacted by the number of non-CPRE projects that execute Interconnection Agreements prior to CPRE Tranche 2 winning Proposals.

The amount of time required to construct System Upgrades varies significantly depending the scope of the System Upgrade.

For the avoidance of doubt, the term of all PPAs shall be 20 years from the Commercial Operation Date (as that term is defined in the PPA).

B. TRANSMISSION GRID LOCATIONAL GUIDANCE

For purposes of the Tranche 2 CPRE RFP, the Companies have provided grid locational guidance on the IA RFP Website indicating known transmission and distribution limitations resulting from the amount of existing or proposed renewable energy facilities in a particular area. This grid locational guidance is intended to provide MPs with information regarding areas on the transmission system where System Upgrade costs are likely based upon recent transmission system studies. The Documents Page of the IA RFP Website includes a map and supporting documentation, including tables of constrained circuits and substations to indicate areas of known transmission constraints in which System Upgrade costs will likely be required. Studies will be required to determine the extent and cost, if any, of these System Upgrades.

Transmission areas not identified as zones of known transmission constraints may still require System Upgrades, and transmission studies will be required to determine the extent and cost, if any, of these System Upgrades.

C. PRODUCTION ESTIMATES

MPs shall include an 8760 production profile for the first year of operation as part of their Proposal. In the case of solar facilities, the required production profile shall be generated in PVSyst. Production profiles should be based on energy delivered at the POI and taking into account all transformation losses to the POI, including final GSU transformation. For example, transmission interconnected projects should include any transformational losses incurred through the GSU to the high-side of the interconnect. For Transmission interconnected Facilities, utility power factor requirements should also be included in determination of energy delivered to the POI.[12] The production profile provided with the Proposal should not be adjusted for Daylight Standard Time.

All Proposals including on-site storage must submit two production profiles for the facility: one profile with the storage option and one profile without the storage option.

D. STORAGE

Energy storage devices must be on the DC side of the inverter and charged exclusively by the Facility. Storage devices must be controlled by the Seller in accordance with the Energy Storage Protocols specified in the pro forma PPA, including in Exhibit 10 thereof.

E. CONTROL INSTRUCTIONS

Section 8.6 to 8.10 of the pro forma PPA addresses DEC and DEP system operators' rights to issue instructions to control the renewable generating facilities procured through the CPRE Program in the same manner as DEC's and DEP's control of the Companies' own generating facilities.[13] CPRE Facilities must be designed with control equipment that will facilitate full or incremental

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[12] DEC requires each Transmission interconnected Facility to be capable of delivering power to the POI within the power factor range of 0.93 lagging to 0.97 leading. DEP requires the Facility to be capable of delivering power to the POI within the power factor range of 0.95 lagging to 0.95 leading.

[13] *See* N.C. Gen. Stat. § 62-110.8(b).

instantaneous control over the Facility[14] in order to take any action directed by the Companies' system operators to implement or otherwise effectuate system operator instruction.

The CPRE dispatch control entitlements are in addition to otherwise applicable system emergency condition instructions and force majeure instructions, as defined in the PPA,[15] and may be issued by the system operator for any reason, including planning its security-constrained unit commitment and dispatch for operational efficiency (*e.g.,* avoid taking a large unit off-line for short intra-day durations to avoid operationally excess energy) or to provide for operational flexibility for anticipated operational challenges (*e.g.,* dispatching down facilities to reduce extreme evening ramp rates).

Section 8.9 of the pro forma PPA specifies that the uncompensated, non-force majeure/emergency conditions CPRE dispatch control entitlement is limited to 5% of the facility's annual expected output in DEC and 10% of the facility's annual expected output in DEP. Compensation at the full contract price will be provided for each MWh of energy that could have been generated but was not due to dispatch down control instruction(s) exceeding the contracted-for percentage CPRE dispatch control entitlement. Section 8.9 and Exhibit 9 to the pro forma PPA also describe the methodology that will determine whether the CPRE dispatch control entitlement was exceeded during a given year and will be used to calculate any compensation owed to the seller under the PPA.

VII. RESERVATION OF RIGHTS

In submitting a Proposal into this RFP, an MP agrees and accepts that nothing contained in this RFP will be construed to require or obligate the Companies to select any Proposal. Per the Commission's CPRE Order, MPs retain the right to initiate a complaint proceeding before the Commission. MPs should be aware that submittals, even if marked "Confidential," may be subject to discovery and disclosure in regulatory or judicial proceedings. The Companies will notify the MP in advance of any required disclosure of confidential information.

[14] As specified in the Energy Storage Protocols in Exhibit 10 of the PPA, DEC/DEP will not have control of the storage resource.

[15] The Companies will manage dispatch control instructions of CPRE Resources and system emergency curtailments in accordance with the Operating Procedures filed January 30, 2018, in Docket No. E-100, Sub 148.

APPENDIX A
PPA

[See attached document]

APPENDIX B
HISTORICALLY UNDERUTILIZED BUSINESSES

As an advocate for corporate responsibility, Duke Energy excels among our utility peers in seeking and developing local and diverse businesses, as well as those with environmentally sustainable practices, through our supply chain sourcing strategy. Including Corporate Responsibility as a standard component of the sourcing process creates a standardized approach when evaluating suppliers, while maintaining flexibility based on opportunity and risk avoidance.

Diverse Supplier Designations

The following designations will be utilized in the CPRE program to qualify a Market Participant as a Historically Underutilized Business:

Designation	Description	Requirement
WBE	Women Owned Business Enterprise	At least 51% owned
MBE	Minority Owned Business	At least 51% owned
VBE	Veteran Owned Business	At least 51% owned
SDVBE	Service Disabled Veteran Owned Business	At least 51% owned

Above business concerns must be at least 51% owned by one or more of individuals in the diverse categories or, in the case of any publicly owned business, at least 51% of the stock is owned by individuals within the groups. In addition, the owners must control the management and daily business operations. In case of a permanent or sever disability, the spouse or caregiver of such a service disabled veteran may control the management and daily operations.

Certification

MP’s that meet one or more of the diverse supplier designations above will be required to complete a self-certification form on the website and will be provided the opportunity to upload third party certifications.

APPENDIX C
FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

Irrevocable Standby Letter of Credit No.: ____________

Date: ______________

Beneficiary:
[Duke Energy legal entity name]___________
550 South Tryon Street, DEC40C
Charlotte, NC 28202
Attention: Chief Risk Officer

Ladies and Gentlemen:

By the order of:

Applicant:
____
____
____

We hereby issue in your favor our irrevocable letter of credit No.: _________ ("Letter of Credit") for the account of ______________ (the "Applicant") for an amount or amounts not to exceed ___________ US Dollars in the aggregate (US$________________) available by your drafts at sight drawn on [Issuing Bank] effective _________________ and expiring at our office on [*insert date which is one year from issuance*] (the "Expiration Date"), unless terminated earlier in accordance with the provisions hereof or otherwise extended.

Funds under this Letter of Credit are available against your draft(s), in the form of attached Annex 1, mentioning our letter of credit number and presented at our office located at [Issuing Bank's address must be in US] and accompanied by a certificate in the form of attached Annex 2 with appropriate blanks completed, purportedly signed by an authorized representative of the Beneficiary, on or before the Expiration Date in accordance with the terms and conditions of this Letter of Credit. Partial drawings under this Letter of Credit are permitted.

We hereby undertake to promptly honor your drawing(s) presented in compliance with the terms of this Letter of Credit, up to the amount then available herein, in no event will payment exceed the amount then available to be drawn under this Letter of Credit.

We engage with you that drafts drawn under and in conformity with the terms of this Letter of Credit will be duly honored on presentation if presented on or before the Expiration Date. Presentation at our office includes presentation in person, by certified, registered, or overnight mail.

This Letter of Credit shall automatically terminate on the earliest of the following to occur: (i) the making by you and payment by us of the drawings in an amount equal to the maximum amount available to be made hereunder; (ii) the date we receive from you a Certificate of Expiration in the form of Annex 3 attached hereto; or (iii) the above stated Expiration Date.

Except as stated herein, this undertaking is not subject to any agreement, condition or qualification. The obligation of [Issuing Bank] under this Letter of Credit is the individual obligation of [Issuing Bank] and is in no way contingent upon reimbursement with respect hereto.

This Letter of Credit is subject to the International Standby Practices 1998, International Chamber Of Commerce Publication No. 590 (“ISP98”). Matters not addressed by ISP98 shall be governed by the laws of the state of New York.

We shall have a reasonable amount of time, not to exceed three (3) business days following the date of our receipt of drawing documents, to examine the documents and determine whether to take up or refuse the documents and to inform you accordingly.

Kindly address all communications with respect to this Letter of Credit to [Issuing Bank’s contact information], specifically referring to the number of this Letter of Credit.

All banking charges are for the account of the Applicant.

This Letter of Credit may not be amended, changed or modified without our express written consent and the consent of the Beneficiary.

Very truly yours
[Issuing Bank]

______________________________ ______________________________
Authorized Signer Authorized Signer

This is an integral part of letter of credit number: *[irrevocable standby letter of credit number]*

ANNEX 1

FORM OF SIGHT DRAFT

[Insert date of sight draft]

To: *[Issuing Bank's name and address]*

For the value received, pay to the order of _______________________ by wire transfer of immediately available funds to the following account:

[name of account]
[account number]
[name and address of bank at which account is maintained]
[aba number]
[reference]

The following amount:

[insert number of dollars in writing] United States Dollars
(US$ *[insert number of dollars in figures]*)

Drawn upon your irrevocable letter of credit No. *[irrevocable standby letter of credit number]* dated *[effective date]*

[Beneficiary]

By: ___________________________
Title: _________________________

This is an integral part of letter of credit number: *[irrevocable standby letter of credit number]*

ANNEX 2

FORM OF CERTIFICATE

[Insert date of certificate]

To: *[issuing bank's name and address]*

Duke Energy_____________ (the "Beneficiary") is drawing the funds requested under this draft based on the below specified draw condition:

[check appropriate draw condition]

[_____] [Legal name of bidding entity] (the "Bidder") has withdrawn its proposal in violation of the bidding rules under the Request for Proposals for the Competitive Procurement of Renewable Energy ("RFP") which was issued by [Insert Beneficiary's name] on [insert date of RFP]; or

[_____] A proposal submitted by [Legal name of bidding entity] (the "Bidder") has been selected as a winning proposal in the Request for Proposals for the Competitive Procurement of Renewable Energy ("RFP") which was issued by [Insert Beneficiary's name] on [insert date of RFP] and Bidder has failed to execute the [*insert name of required contract*] (the "Agreement") within 60 days of the closing of the RFP; or

[Legal name of bidding entity] (the "Bidder") has received a winning proposal in the Request for Proposals for the Competitive Procurement of Renewable Energy ("RFP") which was issued by [Insert Beneficiary's name] on [insert date of RFP] and has failed to meet the creditworthiness requirements under the [*insert name of required contract*] ("Agreement") or to post performance security as required under the Agreement within 5 business days of the execution of the Agreement.

Duke Energy _______________

By: ____________________________

Title:___________________________

ANNEX 3

FORM OF CERTIFICATE OF EXPIRATION

[Insert date of certificate]

To: *[issuing bank's name and address]*

Attention Standby Letter of Credit Unit

Re: irrevocable letter of credit No. *[irrevocable standby letter of credit number]* dated *[effective date]* the "Letter of Credit."

Ladies and Gentlemen:

The undersigned hereby certifies to you that the above referenced Letter of Credit may be cancelled without payment. Attached hereto is the referenced Letter of Credit, marked cancelled.

Duke Energy ________________

By: ____________________________

Title:___________________________

Cc:___________________________[Bidder]

APPENDIX D
FORM OF SURETY BOND

SURETY BOND – COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY

COLLATERAL SECURITY PAYABLE UPON DEMAND

* * * * *

PRINCIPAL / BIDDER *(Legal Name and Business Address)*

SURETY *(Legal Name and Business Address)*	***CONTRACT NO.***	***CONTRACT DATE***
OBLIGEE [Duke Energy Carolinas, LLC][Duke Energy Progress, LLC] ---- *add address* -----	***SURETY BOND EFFECTIVE DATE***	
PROPOSAL SECURITY AMOUNT	***PENAL SUM OF BOND***	

KNOW ALL PERSONS BY THESE PRESENTS THAT: PRINCIPAL (herein, "Bidder") and SURETY are held and firmly bound to [Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC] ("Duke Energy"), a limited liability company organized and existing under the laws of the state of North Carolina, its successors and assigns in the amount of $[*insert Bond Amount*] ("Proposal Security Amount"), for the payment of which the Bidder and Surety, their heirs, executors, administrators, successors and assigns are hereby jointly and severally bound.

WHEREAS, Bidder has submitted a bid proposal into Duke Energy's Request for Proposals for the Competitive Procurement of Renewable Energy ("RFP"), which was issued by Duke Energy on [___________];

WHEREAS, Duke Energy has selected Bidder's proposal (the "Bid") for further evaluation in Step 2 of the RFP process (such evaluation referred to herein as the "Step 2 Evaluation Process") pursuant to the RFP;

WHEREAS, Bidder and Surety acknowledge that the RFP process will be delayed and Duke Energy will be harmed if Bidder withdraws the Bid, or if the Bid is selected as a Bid for the Step 2 Evaluation Process and the Bidder does not execute the RENEWABLE POWER PURCHASE AGREEMENT or the ASSET PURCHASE AND SALE AGREEMENT (as applicable, the "Agreement") associated with the RFP as requested by Duke Energy and/or fails to provide Performance Assurance as required under and as defined in the Agreement; and

WHEREAS, Bidder desires to furnish this Bond pursuant to the requirement in Section III of the RFP to provide Proposal Security for a bid selected to continue forward into the Step 2 Evaluation Process;

NOW THEREFORE, the condition of this obligation is such that if (i) Duke Energy or the Independent Administrator acting on its behalf notifies Bidder that the Bid has been eliminated from consideration in the RFP, or (ii) Duke Energy subsequently selects the Proposal as a winning Proposal under the RFP and Bidder has executed the Agreement and posted Performance Assurance as required in such Agreement, then this obligation will be null and void; otherwise it will remain in full force and effect, subject to the following additional conditions:

1. Capitalized terms undefined herein will take the meaning or definition provided in the RFP or where indicated, the Agreement. In the event of any conflict between this Bond and the RFP, the terms of this Bond will control.

2. If Bidder withdraws the Bid, or if Duke Energy selects the Bid as a winning Proposal and the Bidder does not execute the Agreement with Duke Energy for the Bid within 90 days of the closing of the RFP or fails to meet the creditworthiness requirements or to post the performance security as required under the Agreement within 5 business days of the execution of the Agreement, then Duke Energy will issue a demand for payment of the Proposal Security Amount to the Surety ("Demand for Payment").

3. Surety will, not later than ten (10) days after delivery of a Demand for Payment to the Surety at the address provided below, pay the Proposal Security Amount to Duke Energy. Surety's obligation for payment of the Proposal Security Amount will be deemed established regardless of the underlying causes for Bidder's withdrawal of the Bid and irrespective of any other circumstance whatsoever that might otherwise constitute a legal or equitable discharge or defense of the Surety.

4. Bidder and Surety acknowledge that the Proposal Security Amount represents a fair and reasonable pre-estimation of the damages due to Duke Energy under the circumstances existing as of the Surety Bond Effective Date and that such amount represents a reasonable estimate of Duke Energy's losses in the event of (i) Bidder's withdrawal of the Bid following its selection for further evaluation in the Step 2 Evaluation Process, or (ii) Bidder's failure to execute the Agreement with Duke Energy for the Bid if selected as a winning Proposal or failure to provide Performance Assurance as required under the Agreement. The Proposal Security Amount will not be deemed a penalty, and the Bidder and Surety hereby waive and forfeit any right to contest the reasonableness or validity of the liquidated Proposal Security Amount. Duke Energy's right to recover the Proposal Security Amount will in no way limit its entitlement to other non-monetary remedies to which Duke Energy may be entitled pursuant to the terms of the RFP, the Bond, or applicable law.

5. It is hereby agreed that this obligation is effective beginning on the Surety Bond Effective Date, above, provided that, if this Bond remains in effect after one (1) year following the Surety Bond Effective Date, Bidder may cancel this Bond after such one (1) year period by giving Duke Energy at least forty-five (45) days prior written notice of the cancellation date. Such cancellation notice will be sent by certified mail or by overnight courier with tracking service to:

{Add notice info}

with copy to
[Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC]
Attn: Credit Risk Manager
550 South Tryon Street (DEC40C)
Charlotte, NC 28202

Any obligations of the Bidder prior to any such cancellation will survive such cancellation and continue to be a liability of the Surety until paid in full by the Bidder.

This Bond is irrevocable by Surety.

6. Within thirty (30) days following the date of any notice of cancellation of this Bond that is provided to Duke Energy under Paragraph 6, Bidder will provide to Duke Energy a replacement Bond that satisfies the requirements of Section III of the RFP in the amount of the Performance Security required for the pre-COD period. Bidder's failure to provide such replacement Bond in the required timeframe will constitute a default under this Bond and will entitle Duke Energy to issue a Demand for Payment to the Surety for the payment of the Proposal Security Amount.

7. The Surety's liability is limited to the Proposal Security Amount ("Penal Sum of Bond"), unless suit must be brought for enforcement of the within obligations and in which case the Surety will also be liable for all costs in connection therewith, interest and reasonable attorneys' fees, including costs of and fees for appeals.

8. Failure of the Surety to pay the Proposal Security Amount within ten (10) days of Demand for Payment will constitute default of the Surety's obligation under the Bond and Duke Energy will be entitled to enforce against the Surety any remedy available to it.

9. Surety, for value received, hereby stipulates and agrees that no change, modification, omission, addition or change in or to the RFP or the Agreement, and no action or failure to act by Duke Energy will in any way affect the Surety's obligation on this Bond; and Surety hereby waives notice of any and all such modifications, omissions, alterations, and additions to the terms of the RFP or the Agreement.

10. If any part or provision of this Bond will be declared unenforceable or invalid by a court of competent jurisdiction, such determination in no way will affect the validity or enforceability of the other parts or provisions of this Bond.

11. The undersigned Surety and Bidder are held and firmly bound for the payment of all legal costs, including reasonable attorney's fees, incurred in all or any actions or proceedings taken to enforce

this Bond or the obligations created herein, or payment of any award of judgment rendered against the undersigned Surety. Nothing contained herein will be construed to obligate Duke Energy to pay any fees or expenses incurred in connection with the issuance of this Bond.

12. All disputes relating to the execution, interpretation, construction, performance, or enforcement of the Bond and the rights and obligations thereto will be governed by the laws of, and resolved in the State and Federal courts in North Carolina. The rights and remedies of Duke Energy herein are cumulative and in addition to any and all rights and remedies that may be provided by law or equity.

13. The undersigned Surety agent(s) represent that he/she is a true and lawful attorney-in-fact for the Surety and authorized to bind the Surety hereto and to affix the Surety's corporate seal hereunder, as evidenced by the attached power of attorney.

IN WITNESS WHEREOF, this instrument is SIGNED AND SEALED this _____ day of_______________, 20__.

PRINCIPAL/BIDDER:

For Bidder: ___________________________

Signature: ___________________________

(SEAL)

Name and Title: ___________________________

Address: ___________________________

____

____

SURETY:

Attorney in Fact: ___________________________

Signature: ___________________________

(SEAL) Name and Title: ______________________

Address: ______________________
____
____

AFFIDAVIT AND ACKNOWLEDGEMENT OF ATTORNEY-IN-FACT

STATE OF _____________

COUNTY OF ___________

I hereby certify that I am the attorney-in-fact of ______________________, a [*insert entity type*], which is the surety in the foregoing bond, and that I am authorized to execute on the above Surety's behalf the foregoing bond pursuant to the Power of Attorney dated ____________ and attached hereto, and on behalf of the Surety, acknowledge the foregoing bond before me as the above Surety's act and deed.

Given under my hand this _____ day of ____________.

____
ATTORNEY-IN-FACT

____
PRINT NAME

(NOTARY SEAL)

APPENDIX E
REQUIRED FINANCIAL INFORMATION

A. Description of ownership and proposed financing arrangements, including the expected percentage of debt and equity capital that the bidder has committed to secure.
B. Annual reports for the past three (3) years and any Form 10-K and 10-Q filings since the period covered in the last annual report. If these documents are not available, then audited financial statements for the last three (3) years will be accepted. All financial statements, annual reports, and other large documents may be referenced via a website address. If a bidder has not been in operation for three (3) years, please provide the above information, as applicable, since the commencement of operation.
C. Dunn and Bradstreet identification number.
D. Documentation of the bidder's (or parent's if applicable) credit ratings from S&P, Moody's, or Fitch rating services, if rated.
E. Details related to its banking relationships or liquidity.
F. Description of plans for acquiring the necessary funds for developing and operating the Facility, including a discussion of the Facility's legal ownership structure, the expected percentage of debt and equity capital that the bidder has committed to secure, and the identity and credit rating or other financial information indicative of the financial strength of firms that are likely to provide such financing.
G. Any additional documentation needed to determine the bidder's financial strength and the strength of any corporate parents.

Exhibit 3

APPENDIX F
SAMPLE SCORING SHEET

Bid Scoring Categories	Bid Score	% of Bid Score	Description	Individual Categories	Maximum Scoring	Section Score
1. Price Score		60%	Includes fixed and variable bid costs	The price score will be calculated on the basis of the bid's projected total cost per MWH	600	600
2. Project Development Criteria		15%	Respondent must show sufficient evidence of ability to provide services included in proposal for the contract term Evidence of operational capability to provide proposed services	-Demonstrate that permitting will be complete to meet COD -Experience of project team -Project Site control for full term -Site control to POI for full term	30 30 50 50	160
3a. Facility Project Characteristics 3b. Transmission Project Characteristics		15%	Evidence of equipment designed to meet specifications Interconnection Transmission Rights	-Equipment to be used -Required control equipment (TBD) -Quality of project design -Submitted completed interconnected request and obtained a queue number	30 30 30 50	90 50
4. Project Characteristics		4.5%	Value of Project Characteristics	Demonstrates ability to meet performance guarantee and liquidated damages pursuant to the PPA	45	45
5. Historically Underutilized Businesses		.5%	Ownership by Minorities (to be defined)	Ascertain that at least 51% of venture is owned by eligible minority	5	5
6. Credit Worthiness		5%	Financial assurances to meet schedule and milestones in PPA	-Confirms meeting all Duke credit requirements -Pass: MP provides acceptable Proposal Security - Fail: MP does not provide acceptable Proposal Security	50 50 0	50
Total Score	1,000	100%			1,000	

APPENDIX G
RECOMMENDATIONS FOR ESTABLISHING NATIVE POLLINATOR HABITAT ON SOLAR FARMS IN NORTH CAROLINA

[See attached document]

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Exhibit 4

CPRE Program Independent Administrator's
Report on Tranche 2 Stakeholder Process

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program	)	**REPORT OF THE INDEPENDENT ADMINISTRATOR – TRANCHE II STAKEHOLDER PROCESS**

I. EXECUTIVE SUMMARY

Accion Group, LLC, the Competitive Procurement Renewable Energy ("CPRE") Independent Administrator ("IA") conducted two meetings with Stakeholders. The meetings were held to continue discussions on lessons learned in the Tranche I CPRE RFP Solicitation and soliciting feedback on the RFP documents that relate to the Tranche II CPRE RFP Solicitation. The Stakeholders addressed issues identified by the NCUC and the Public Staff of the NCUC ("Public Staff") and topics identified as important for consideration as part of determining the scope and terms of Tranche II. Participants included representatives of the Public Staff, Duke Energy, Market Participants ("MPs") and the IA. Collectively, these are referred to as "Stakeholders".

A goal of the meetings was to provide the Commission with a succinct statement of the issues the Stakeholders believe should be addressed by the NCUC before Tranche II is released, and to identify where the Stakeholders agree on an appropriate design for Tranche II. Further, a goal was to identify issues the Stakeholders would like the Commission to address, but for which the Stakeholders have not reached consensus. It is hoped that a uniform statement of issues will assist the Commission by identifying matters of concern to participants in the CPRE program.

The IA believes the discussions were productive and the Stakeholders participated in good faith to achieve the common goal of releasing Tranche II in a timely manner with modifications to the Tranche I design that would enhance the ability of MPs to participate by submitting attractive proposals at or below Avoided Cost. Below the IA identifies the issues discussed and distinguishes between where the IA believes the Stakeholders reached consensus of how issues should be managed and where there remains a difference of opinion on how to resolve certain issues before Tranche II is released.

The IA respectfully requests the Commission give full weight to the views of the Stakeholders and the IA when fashioning the requirements and scope for CPRE Tranche II.

II. SUMMARY OF ISSUES

A. ISSUES WHERE CONSENSUS EXISTS [1]

In order to have Tranche II proceed in the timeframe called for in North Carolina G.S. 62-110.8, the Stakeholders identified issues that, collectively, they believed needed to be addressed before Tranche II is released. The IA believes consensus was reached on some issues, and not for others. It should be noted that as used in this report, the IA means that on individual issues Stakeholders might have differing viewpoints, but in the interest of moving forward with Tranche II Stakeholders were agreeable to accepting the approach the IA characterizes as consensus. In Section III there is more detailed explanation of the positions of the Stakeholders.

1. Duke should continue to be able to recover the grid upgrade costs assigned to winning proposals in rates. [2]

2. MPs should continue to include interconnection costs (i.e., at the point of interconnection) in their proposals, but should not be required to include grid upgrade costs in proposals.

3. If grid upgrade costs are borne directly by the MP, MPs should be permitted to refresh their proposals after receiving grid upgrade costs from Duke.

4. Duke should provide updated grid location guidance including maps and details on constrained lines and substations after the conclusion of Tranche I. Tranche II should not restrict proposals to areas outside of those identified as having constraints.

5. The inclusion of energy storage in the CPRE program should continue as in Tranche I, but the statutory requirements of the CPRE program present practical limitations on the approach to expanding storage in CPRE.

6. Tranche II should proceed so proposals are submitted in 2019.

7. It is preferable to have more pricing periods in Tranche II than in Tranche I (Tranche I had three).

[1] Except where specifically noted, the Public Staff took no position on the issues identified herein.
[2] The Stakeholders recognized that regulatory approval in both Carolinas would be necessary.

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8. The Tranche II avoided cost and the number of pricing periods should be based on those approved by the NCUC in the avoided cost docket (Docket No. E-100, Sub 158), ("Avoided Cost Order"), if the final decisions are rendered on a schedule that permits Tranche II bidding in 2019.

9. If the Avoided Cost Order is not available before October 2019, the Avoided Cost methodology approved in Docket No. E-100 Sub 148 should be used in Tranche II. At the same time, the Stakeholders agreed that having more pricing periods than in Tranche I would be appropriate.

10. There should continue to be a Required Commercial Operation Date ("RCOD") established for projects proposed in CPRE.

11. If MPs are compensated for expected output that is not delivered as a result of curtailment (other than system reliability curtailment), then Duke should recover the cost through rates in all jurisdictions. [3]

12. If the IA again has a "reserve list" in addition to establishing the Competitive Tier during Step 1, then the IA should provide more than a seven (7) day notice of when a proposal would have to provide Proposal Security.

13. The Tranche II Renewable Purchase Power Agreement ("RPPA") should clarify the process for determining when the MPs are to provide the requisite Performance Security.

14. Late Stage Projects should not receive the same treatment as in Tranche I.

15. The Stakeholders agreed the CPRE program should proceed with the release of Tranche II while transmission queue reform continues at the same time.

16. More transparency regarding the evaluation methodology and ranking of proposals should be shared by the IA prior to the release of Tranche II.

B. ISSUES WHERE CONSENSUS DOES NOT EXIST

The Stakeholders agreed that the following matters should be addressed by the NCUC before Tranche II is released but did not reach consensus on a recommended course of action.

1. Whether the contracts used by the DEC/DEP Proposal Team for projects submitted for Asset Acquisition should be non-negotiable and reviewed by the IA and approved by the NCUC prior to bidding.

[3] The Stakeholders recognized that regulatory approval in both of the Carolinas would be necessary.

2. Whether MPs should be compensated for all or part of any delivery that is curtailed, other than for system reliability curtailment.

3. Transmission queue treatment: Setting the Tranche II and Tranche III queue position for CPRE proposals at an early date (i.e. prior to the RFP issuance or proposal due dates for these Tranches) would be appropriate for future Tranches.

4. Whether there should be an extension of the RCOD (and default date) due to unforeseeable project delays or Duke grid upgrade delays.

5. Whether the IA should publish post-Step 1 ranking.

6. The "cluster study" process to be used in Tranche II should be identified and should be released before the start of Tranche II.

7. The amount of and timing for providing the Pre-COD Performance Assurance under the RPPA should be revised.

III. DISCUSSION OF ISSUES

A. ISSUES WHERE CONSENSUS EXISTS

The IA provides the following discussions of individual issues in the interest of assisting the NCUC in appreciating the reasoning behind each issue for which there is consensus among the Stakeholders.

1. Duke should continue to be able to recover the grid upgrade costs assigned to winning proposals in base rates.

The NCUC requested that Stakeholders address these two related questions:

a. Whether to change the CPRE program plan to remove the ability of Duke to recover grid upgrade costs in base rates.
b. Whether to change the CPRE program plan to require the initial proposal to contain all of the Interconnection Customer's costs.

The Stakeholders agreed that it would be impractical for the MPs to include the cost of grid upgrades in proposal pricing because those costs would generally not be known at the time proposals are submitted. Further, attempting to adjust the proposal pricing after the fact would introduce unnecessary complexity into the process and could invite "gaming" by MPs who chose to include artificially low pricing in initial proposals.

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The Stakeholders agreed that Duke would be unable to provide a system upgrade cost for any project until it is known which projects are proposed in Tranche II. Also, the Stakeholders agreed that Duke would be unable to provide a firm estimate for grid upgrade costs unless Duke included a significant amount for unknown expenses. Similarly, the Stakeholders agreed that it would be highly unlikely any MP would accept full responsibility for grid upgrade costs without also including an amount for unknown contingencies. Accordingly, the Stakeholders agreed that the proposals presented would, by necessity, have overstated costs included. The result would be reduced participation by MPs and less cost-effective proposals for Duke customers.

2. MPs should continue to include interconnection costs (i.e., at the point of interconnection), but should not be required to include grid upgrade costs in proposals.

There was agreement that MPs should be responsible for the actual cost of interconnecting to the Duke system, and that those costs should be included in initial proposal pricing.

3. MPs should be permitted to refresh proposals, if grid upgrade costs are borne directly by the MP. However, Stakeholders did not reach consensus on whether there exists a practical way to effectuate a refresh process.

The NCUC requested interested parties address the following issue:

> Whether to revise the CPRE process to allow competitive MPs to refresh their proposals based upon the assessment of grid upgrades identified in Step Two of the CPRE RFP proposal evaluation process.

As noted above, the Stakeholders strongly believe that grid upgrade costs assigned to winning proposals should be recovered from Duke customers through base rates. The process used in Tranche I of imputing the cost of grid upgrade costs to projects during the Step 2 iterative process was accepted as an appropriate way to assess the full cost of a project to the Duke system. However, if MPs are required to bear the cost of assigned grid upgrade costs, the Stakeholders agreed that a system permitting proposal price refresh would be appropriate.

The Stakeholders recognized that there are a number of ways refreshing could be employed, including:

a. Permitting a refresh of proposal pricing during Step 2 when grid upgrade costs are identified;

b. Permitting refreshing of all proposals' pricing – regardless of whether they are in the competitive tier and whether the associated grid upgrade costs are known – during Step 2;

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c. Permitting MPs to refresh proposal pricing for changes in market conditions and equipment supply costs; and,

d. Permitting sequential refreshing as grid upgrade costs are determined and the iterative process of Step 2 re-ranks proposals.

While some Stakeholders advocated each of these approaches, each has challenges. If there is to be an opportunity for refreshing proposal pricing, the IA believes the most appropriate approach would be a one-time refresh only for proposals for which the associated grid upgrade cost is calculated. At the same time, the IA notes that this would be within the Step 2 iterative process, as the assigned costs change as projects are eliminated and others added as part of the "cluster study" process. To avoid the refresh process being an endless loop, the IA believes a one-time refresh would be necessary, and that it should be available at the time the initial grid upgrade costs are assigned to a project.

4. Duke should provide updated grid location guidance including maps and details on constrained lines and substations after the conclusion of Tranche I. Tranche II should not restrict proposals to areas outside of those identified as having constraints.

The NCUC directed interested parties:

To explore options for Duke to more specifically direct generators to locations on the system that will not involve major network upgrades.

The Stakeholders agreed that once Tranche I is completed, the grid location guidance should be updated to reflect the change in available transmission capacity. The Stakeholders also agreed that MPs should not be restricted to submitting proposals to only specific points of interconnection or areas not identified as having constraints because that could increase the cost of land and leases on land, as well as deny MPs who are willing to bear some or all of grid upgrade costs. MPs also expressed concern that limiting projects to specific areas could result in some municipalities and counties imposing moratoria on new projects while studying the impact of concentration of renewable projects.

5. The inclusion of energy storage in the CPRE program should continue as in Tranche I, but the statutory requirements of the CPRE program present practical limitations on the approach to expanding storage in CPRE.

In the Stakeholder session on February 22, 2019, IA presented a list of ways energy storage is being deployed in other jurisdictions (Attachment A). The Stakeholders agreed the list was comprehensive. Further, the Stakeholders agreed that energy storage should be included in CPRE, but that under the CPRE design, the only option for compensating storage was for energy

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and capacity that was recharged 100% from the renewable project for the full 20-year term of an RPPA, the same as allowed in Tranche I.

The parties did not reach consensus on other areas of importance related to storage such as whether the Buyer or Seller controls the storage asset, how storage should be priced, and how the storage protocols in the RPPA are defined. In light of the range of views on how energy storage should be included in Tranche II, the IA anticipates MPs and Duke will share those views in separate filings.

6. Tranche II should proceed so proposals are submitted in 2019.

The Stakeholders were in agreement that Tranche II should be released without delay. The reasons for this view was the concern that federal tax incentives are scheduled to decrease, and may not be available in the future, and that delays in implementation could result in less cost-effective proposals for Duke customers.

7. It is preferable to have more pricing periods than in Tranche I (Tranche I had three).

Participants, including the Public Staff, indicated that pricing periods with additional granularity, such as those proposed in the E-100 Sub 158 avoided cost docket, are preferable and can serve to enhance the value of potential proposals with energy storage. There was no discussion about the specific definitions of these pricing periods and therefore no consensus on that matter.

8. Avoided cost and the number of pricing periods should be those approved by the NCUC in Docket No. E-100 Sub 158, if the final Avoided Cost Order is issued in time for Tranche II bidding in 2019.

As noted immediately above, the Stakeholders agreed that having more granularity of pricing periods is desired. The IA will model the evaluation and the proposal form to comport to the design approved by the NCUC.

The Stakeholders would prefer to have the most recent Avoided Cost methodology and pricing periods applied to the Tranche II solicitation. At the same time, the Stakeholders prefer to have Tranche II document review process, et al, begin without delay, but concern was expressed that opening the Tranche II process would necessitate using the presently approved Avoided Cost methodology and pricing periods, and not permit deployment of any improvements that are the result of the Avoided Cost Order. The Stakeholders agreed that clarification of the CPRE program rules to permit completion of the Tranche II procedural requirements, with submission of proposals held until the NCUC approves the revised Avoided Cost methodology would be preferred. As noted below, the Stakeholders expressed the desire to get started with

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Tranche II without delay, and that there should be a finite date by which the determination of whether to proceed with the existing Avoided Cost methodology.

9. If the Avoided Cost Order is not available before October 2019, the Avoided Cost methodology approved in Docket No. E-100 Sub 148 should be used in Tranche II. At the same time, the Stakeholders agreed that having more pricing periods than in Tranche I would be appropriate.

The Stakeholders acknowledged that protracted proceedings could result in the NCUC rendering decisions on the Avoided Cost methodology and pricing periods until late in 2019, or even later. To avoid an extended delay in submitting proposals in Tranche II, the Stakeholders agreed there should be a date at which the existing approved Avoided Cost methodology will be employed, absent a final decision of the NCUC. The Stakeholders agreed that submission of proposals in 2019 would be preferred.[4]

10. There should continue to be a Required Commercial Operation Date ("RCOD") established for projects proposed in CPRE.

The Stakeholders unanimously agreed it is important to have a firm in-service date in order for qualified projects to move forward. Indeed, the firm RCOD was acknowledged as necessary for meaningful comparison of projects, and to prevent "phantom" projects from retaining queue presence when they are unable to commit to being in-service.

11. If MPs are compensated for expected output that is not delivered as a result of curtailment (other than system reliability curtailment) Duke should recover the cost through rates.

The risk of curtailment, other than when necessary for system reliability, results in MPs including some risk premium to the proposal price. At the same time, presently Duke is permitted to curtail based on a next least cost generation calculation up to specific limits included in the Pro Forma PPA, and therefore does not incur cost for the curtailment up to the specified limits and is not required to compensate MPs for the non-delivered output up to the specified limits. The Stakeholders agreed that if the risk of curtailment without compensation were eliminated, MPs should be able to offer lower cost proposals.

The Stakeholders recognized that without cost recovery, Duke is unwilling to compensate MPs for curtailment. Therefore, the Stakeholders would support a curtailment policy that permits Duke to recover all of the cost of paying MPs for curtailed output, provided Duke is permitted to recover the cost from customers. [5] The Public Staff expressed concerns that

[4] The Tranche I proposals were submitted on October 9, 2018.

[5] The Public Staff did not take a position on this approach.

if curtailment was compensated and there were no limits on curtailment (other for system reliability), the utility and the developer may not have the incentives to operate the facility in the most efficient manner.

12. If the IA again has a "reserve list" in addition to establishing the Competitive Tier during Step 1, the IA should provide more than a seven (7) day notice of when a proposal would have to provide Proposal Security.

The IA instituted the "reserve list" structure so MPs would only post Proposal Security when their proposal is put in the competitive tier. While MPs appreciated not incurring the expense of Proposal Security prematurely, the IA acknowledges that uncertainty in when a proposal may be moved to the competitive tier, and therefore have to post Proposal Security, creates a challenge for some MPs. The IA will include an "early warning system" in Tranche II so MPs will have ample notice of when Proposal Security will be required.

13. The Tranche II Renewable Purchase Power Agreement ("RPPA") should clarify the process for determining when the MP is to provide the requisite Performance Security.

While the Stakeholders agreed revision would be appropriate, there was no consensus on whether the amount or timing of Performance Security should be revised. (See: non-consensus items below.)

14. The Tranche I treatment of Late Stage Projects should not be applied to Tranche II.

While the treatment of Late Stage Projects was raised during the discussions, no Stakeholder suggested incorporating the Tranche I treatment in Tranche II. Accordingly, the IA believes the Stakeholders are in agreement that the Late Stage Projects definition and concept is not applicable in Tranche II. [6]

15. The Stakeholders agreed the CPRE program should proceed with the release of Tranche II, while transmission queue reform continues at the same time.

B. ISSUES WHERE CONSENSUS DOES NOT EXIST

The Stakeholders agreed there are some matters that should be addressed by the NCUC before Tranche II is released, but the Stakeholders were unable to reach consensus on a recommended course of action.

[6] In Tranche I Late Stage Projects retained their original transmission queue position and were not included in the CPRE Transmission Queue position.

1. Whether the contracts used by the DEC/DEP Proposal Teams for project submitted for Asset Acquisition should be non-negotiable and reviewed by the IA and approved by the NCUC prior to bidding.

Some Stakeholders raised the desire to have contracts used by Duke with acquisition proposals be reviewed by the IA and approved by the NCUC. The IA understands the Commission previously determined this was not required. The stated reason for requiring pre-approval of contracts by the Commission was to permit all acquisition proposals be on an equal footing as to the construction schedule and financing needs.

2. Whether MPs should be compensated for all or part of expected output that is curtailed, other than for system reliability curtailment.

The issue of curtailment is discussed in the prior section. There is no consensus on whether compensation is appropriate, and if so the level of compensation to be made.

3. Transmission queue treatment: Setting the Tranche II and Tranche III queue position for CPRE proposals at an early date would assist in queue-wide reform.

At the urging of the IA, the Stakeholders discussed the immediate establishment of a transmission queue position for Tranche II projects. An alternative identified by the IA would be to establish the CPRE queue position when Tranche II is commenced or before, so those projects would be evaluated for grid impact without the base case including projects that had more recently sought a queue position. It was also discussed establishing a transmission queue position for Tranche III at the same time and for the same reasons.

The IA's identification of an alternative approach was part of the discussion focused on identifying ways to make the transmission queue more accurately include projects that are likely to be developed in the near term. The IA supports the concept and urges the Commission to consider this as one step towards a redesigned transmission queue.

4. Whether there should be an extension of the RCOD (and default date) due to unforeseeable project delays, and whether Duke should compensate MPs in the event Duke is unable to complete required grid upgrades resulting in a delay in a project reaching the contractual RCOD.

5. Whether the IA should publish post-Step 1 ranking.

The IA will seek guidance from the Commission regarding what information may be released publicly. The IA is unaware of the value of identifying a ranking of proposals before the Step 2 analysis is completed and is reluctant to release the identity of MPs or projects without clear direction from the Commission.

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6. The "cluster study" process should be identified and should be released before the start of Tranche II. [7]

7. The amount of and timing for providing the Pre-COD Performance Assurance under the RPPA should be revised.

8. Whether there are ways to expand competitive solicitation of energy storage in the CPRE program after Tranche II.

MP's expressed concern over both the amount required for this Performance Assurance and the timeline in which a winning proposal that has executed the RPPA is required to provide it. The parties did not reach consensus on this issue.

IV. PROCESS

The IA conducted two public sessions with stakeholders to discuss the issues identified by the Commission and to identify areas the parties believed should be addressed by the Commission in advance of the release of Tranche II. The parties agreed it would be appropriate and useful to present the Commission with a list of issues, and to indicate where the parties were in agreement on how those issues should be managed. In this section the IA summarizes the two sessions.

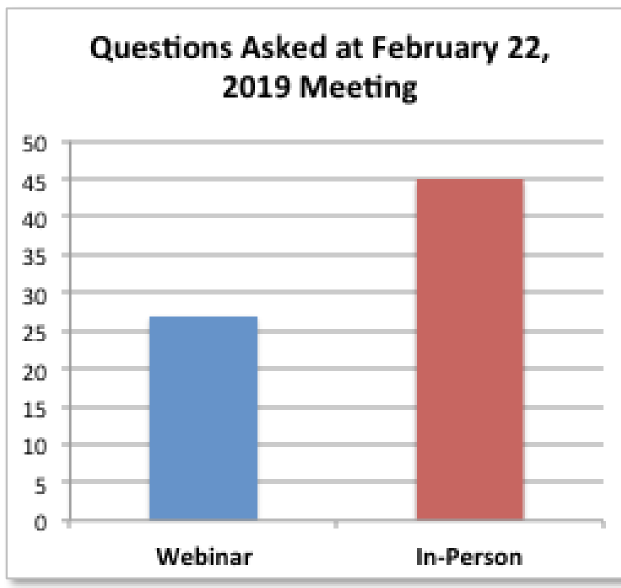
Representatives of Duke, the Public Staff, the IA, and Market Participants were actively involved in each discussion session, either in-person or via a webinar platform. The IA believes the participants were sincere in wanting to reach consensus on the issues to be addressed in advance of the release of Tranche II, and that they participated in good faith.

The February 22, 2019 Stakeholder's Meeting was announced on February 1, 2019 via the website Announcements page; all registered users of the three CPRE silos received an email with the announcement and an invitation to register to participate. To encourage participation, stakeholder meeting participation could be done in-person or via a webinar. The registration opened on February 1, 2019, and registration forms were available for either in-person or webinar participation on the IA website. The IA website has three sections: DEC, DEP, and Acquisition. Registration could be done on either the DEC or DEP sections. Registered users of the Acquisition silo were directed to register on either the DEC or DEP silo.

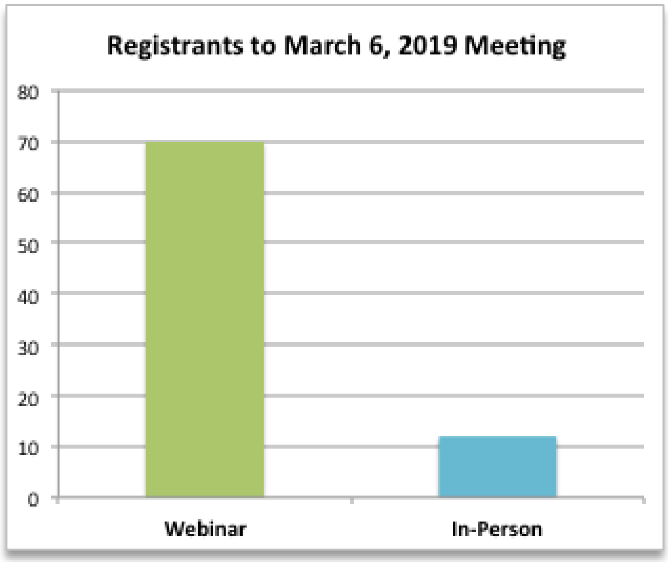
[7] This issue was raised during the second meeting, so there was insufficient time for all parties to discuss fully. The IA and Duke expect to include details on the cluster study process when the Tranche II solicitation documents are released.

Announcements were posted on each website section online and e-mailed to all registered users on February 7, 2019, February 10, 2019, and February 18, 2019 reminding users to register for the meeting. Between February 1, 2019 and the conclusion of the Stakeholder's Meeting on February 22, sixty-one (61) individuals registered across both silos for webinar access, and twenty-three (23) users registered to attend in person. On February 21, 2019 users registered to attend the webinar were sent call-in directions and those users registered to attend in-person were sent meeting location directions. These messages were sent both at 12:00 PM and 5:00 PM on the day prior to the meeting. Users who registered after these messages were sent were shown access details upon registration. The IA further emailed the PowerPoint presentation used in the meeting on February 22, 2019 to all registrants of the meeting. The presentation was also posted on the document page of the IA website.

The Stakeholder's Meeting was conducted at the Duke Energy Headquarters building in Raleigh, North Carolina. The meeting lasted two hours and fifteen minutes and covered a wide range of topics regarding the CPRE program and what changes were needed or requested for Tranche II. The IA moderated the meeting and fielded questions from those in the room and from those on the webinar. Forty-five (45) questions and comments were fielded within the room and seventeen questions were asked and ten comments were made online. Collectively, more than twenty (20) participants were heard in the meeting. A recording of the meeting was posted on the website in its entirety on February 25, 2019.



Following the February 22, 2019 meeting, the IA established a message board on the website for confidential communication between stakeholders and the IA about topics for discussion in the March 6, 2019 meeting. This message board was available to all registrants of the CPRE website and was made available until March 5, 2019. Two interested persons used the message board to ask four questions and raise twelve issues for discussion before the second meeting.



The March 6, 2019, Stakeholder's Meeting was announced at the conclusion of the February 22 meeting. An announcement was posted on February 25, 2019 to each silo of the CPRE site and was emailed to all registered users. Registration to attend the February 6, 2019 meeting either in person or via webinar was opened on February 25, 2019 on all three silos of the website. A reminder announcement was posted on March 4, 2019 and was subsequently emailed to all registered users. In total, seventy (70) users registered for webinar access while twelve (12) users registered to attend the meeting in person. On March 5, 2019 users registered to attend the webinar were sent call-in directions and those users registered to attend in-person were sent meeting location directions. These messages were sent both at 12:00 PM and 5:00 PM on the day prior to the meeting. Users who registered after these messages were sent were shown access details upon registration. The IA further emailed the PowerPoint presentation used in the meeting on March 6, 2019 to all registrants of the meeting. The presentation was also posted on the document page of the IA website.

The second Stakeholder's Meeting was conducted at the Duke Energy Headquarters building in Raleigh, North Carolina. The IA moderated the meeting and led discussion on a wide

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range of topics. In total, fourteen (14) questions and one comment were made via the webinar and more than twenty-seven (27) questions and comments were made in person. Collectively, more than fifteen participants were heard. A recording of the meeting was posted in its entirety on the IA website on March 7, 2019.

The IA believes the level of participation represented interest in the CPRE program and the willingness of Stakeholders to collectively participate in reaching consensus on issues. The discussion was on a professional level, robust, and included frank expressions of what is needed for Tranche II to receive attractive proposals.

V. CONCLUSION

The IA believes the Stakeholder meetings were well publicized and attracted a significant number of participants. The IA believes that, while the Stakeholders discussed a number of additional matters, the issues identified herein are the ones the Stakeholders believe should be resolved by the NCUC before Tranche II begins. Further, the Stakeholders firmly expressed the desire for Tranche II to commence without delay so that projects can move forward. The Stakeholders also agreed that queue-wide reform should proceed separately.

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ATTACHMENT A

STORAGE PRODUCTS AND ATTRIBUTES

1. **Load Following: Production Shifting**
   - Facility that adjusts output in coordination with demand. Produces only enough power to meet demand.

2. **Distributed Storage to Avoid Transmission Investment**
   - Locate storage at distributed locations to meet peak needs

3. **Spinning Reserve**
   - On-line reserve capacity synchronized to the grid that can respond within 10 minutes to compensate for shortfalls

4. **Non-Spinning Reserve**
   - Off-line generation capacity that can be synchronized to grid within 10 minutes to compensate for shortfalls

5. **Fast Start/Fast Ramping**
   - Facility that can stop and start on command.

6. **Volt-Ampere Reactive (Var) Support**
   - Solar and Wind produce low to no reactive power. Hence, support is needed to produce reactive power to maintain voltage stability

7. **Voltage Regulation**
   - Battery storage systems used to solve voltage rise during peak PV generation as well as voltage drop while meeting peak load

8. **Generation Efficiency**
   - Use storage for short-term needs (peaking & other)
   - Avoid Start Up costs of higher cost generation

9. **Maximize Low Cost Units**
   - Avoid shut down of low cost units by charging batteries

10. **Frequency Regulation**
    - Energy storage to regulate AC frequency

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